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A RISK AND COST ANALYSIS OF TRANSPORTING SOUTHERN CALIFORNIA OUTER CONTINENTAL SHELF OIL

Booz-Allen and Hamilton, Incorporated

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for

The U. S. Environmental Protection Agency

Office of Planning and Management
Washington, D.C.

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BOOZ · ALLEN & HAMILTON Inc.

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This study evaluates the risk of oil spills and the costs associated with alternative modes of transporting oil from proposed new Outer Continental Sheld (OCS) lease areas to onshore facilities in southern California. The objective is to assess oil transport risks and costs for specific hypothetical production sites in a formal, analytical fashion to provide policymakers with a clearer picture of approprate development options.

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EXECUTIVE SUMMARY

1. OBJECTIVES OF THE STUDY

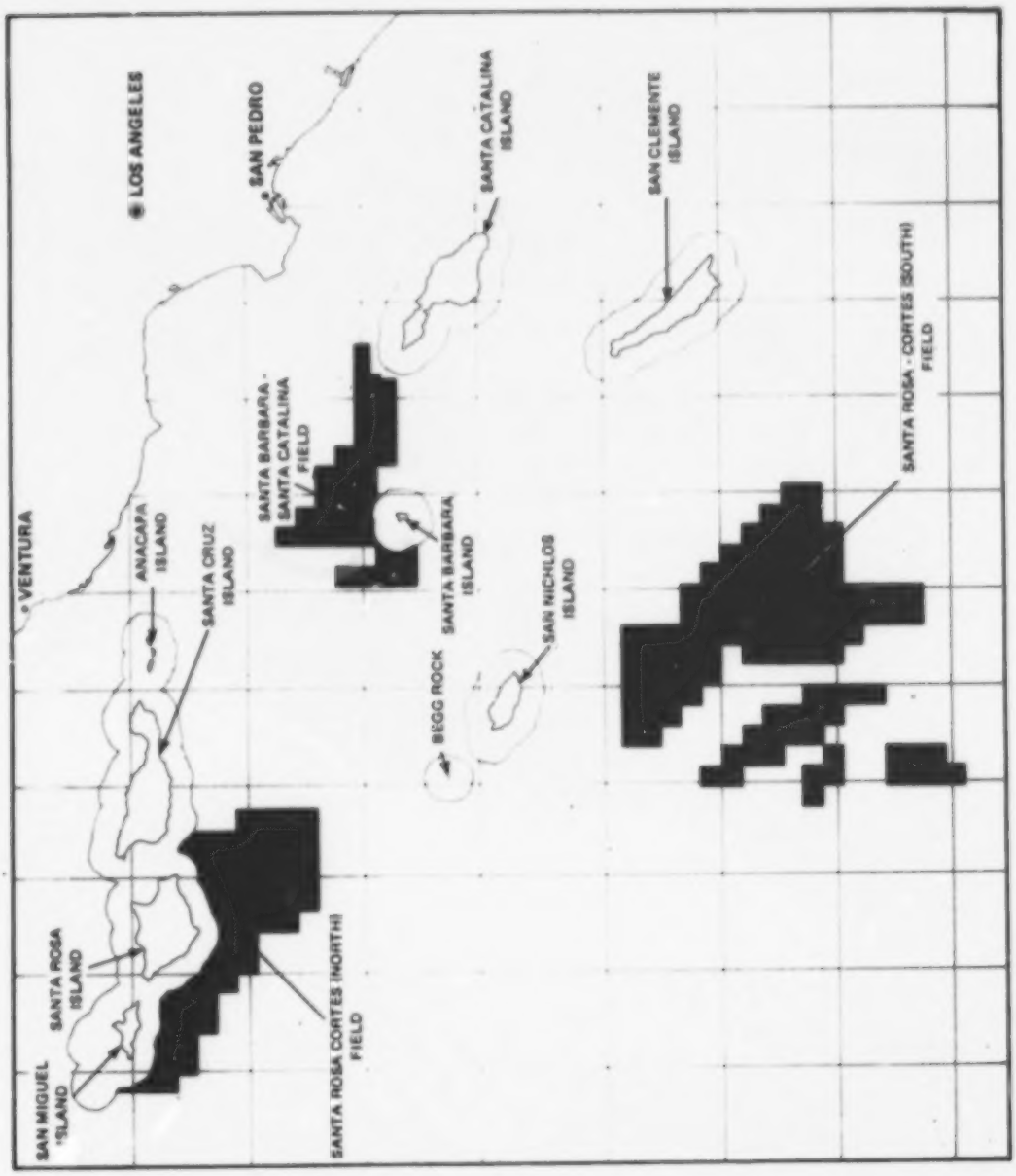
This study has been undertaken for the Environmental Protection Agency for the purpose of evaluating the risk of oil spills and the costs associated with alternative modes of transporting oil from proposed new Outer Continental Shelf (OCS) lease areas to onshore facilities in southern California. The objective is to assess oil transport risks and costs for specific hypothetical production sites in a formal, analytical fashion to provide policymakers with a clearer picture of appropriate development options.

2. TECHNOLOGY OPTIONS

The alternative transport modes included in the study are surface marine vessels (tankers or barges) and pipelines. Marine transport and pipeline systems and routes are specified for each of the three hypothetical sites shown in Figure S-1. Storage systems for the surface marine option are also specified and their costs estimated as part of the overall transport system. Only the risk of oil spills emanating directly from marine vessels and pipelines are

FIGURE S-1

Proposed Southern California
Oil Lease Fields



included in the scope of the study, not the risk associated with storage systems or production platforms.

The pipeline routes analyzed in the study reach depths up to 3,000 feet. Pipelining at such depths has not yet been attempted, but the technology is evolving rapidly. Small diameter pipelines, 12-inch I.D. and less, have been laid as deep as 500 feet. It is anticipated that the capability to transport crude oil by pipeline at 3,000-foot depths will be achieved by the time the wells are producing. Production is expected to commence in three to eight years, provided the lease sale is held in 1975.

3. RESULTS OF THE STUDY

The results of this study are summarized below in Table S-1. The table indicates that from an economic perspective:

- For the Santa Rosa-Cortes North site, the shallow water pipeline is the least costly alternative at both the high and low estimates of reserves. The deepwater pipeline alternative, characterized by a minimum of 3 miles clearance from the Channel Islands, is more expensive than the tanker option based on the low estimate of reserves and slightly less expensive based on the high estimate.

Table S-1
Summary of Results

	Distance To Shore (miles)	Estimated Reserves (10^6 barrels)		Per Barrel Cost (cents)		Expected Total Volume of Oil Spilled, Field Life (barrels)	
		Low	High	Low	High	Low	High
Santa Rosa-Cortes (N)							
Tanker	50	242	431	22	19	21,200	48,300
Deepwater Pipeline Route	54	242	431	28	18	3,200	6,800
Shallow Water Pipeline Route (direct across Santa Cruz Island)	42	242	431	13	9	3,200	6,800
Santa Barbara-Santa Catalina							
Tanker	22	67	219	60	21	3,100	13,200
Pipeline	20	67	219	24	11	600	2,600
Santa Rosa-Cortes (S)							
Tanker	81	239	660	28	21	20,200	89,400
Pipeline (pump station on Santa Cruz Island)	109	239	660	56	33	3,200	13,400

- For the Santa Barbara-Santa Catalina site, the pipeline alternative is clearly the most cost-effective alternative at both the low and high estimates of reserves. Tug barges are less expensive than tankers for this site but still more expensive than pipelines.

- For the Santa Rosa-Cortes South site, which is the farthest site from shore, the tanker is the most cost-effective alternative at both the low and high estimates of reserves.

The factors that govern the selection of alternative transportation modes on the basis of economics include:

- The amount of recoverable reserves

- The distance from the collection point to the onshore terminal

- The depth of water at the production site and along the transport route.

The estimates of the expected total volume of oil spilled over the life of each field indicate that:

- Pipelines are safer by a factor of 7 in the case of Santa Rosa-Cortes (North)

- Pipelines are safer by a factor of 5 in the case of Santa Barbara-Santa Catalina

- Pipelines are safer by a factor of 6.5 in the case of Santa Rosa-Cortes (South).

In all of the hypothetical scenarios, at least 97 percent of the expected total volume of oil spilled will come from a very small number of large spills. For example, in the case of the Santa Rosa-Cortes (North) site, based on the low estimate of reserves, only one tanker spill greater than 1,000 barrels is expected to occur during the life of the field, accounting for 99 percent of the expected total volume spilled. As many as 46 spills less than 1,000 barrels, most less than 3 barrels, are expected to account for only 1 percent of the total amount spilled.

Earthquake risk is not expected to be a great enough factor to significantly alter the volume of oil spilled by an offshore pipeline over the life of an oil field. An earthquake-caused oil spill is expected once every 250 to 1,400 years for each of the production sites.

4. LIMITATIONS OF THE RESULTS OF THIS STUDY

The analysis performed during the course of this study and the resultant findings are heavily dependent upon the accuracy and applicability of available data on oil spills and costs of pipelines and marine transport systems. Although the analysis makes use of the best data available, the results presented above must be interpreted with the following data limitations in mind:

- Available oil spill statistics from the southern California area are incomplete and not wholly representative of the transport modes under consideration. Therefore, oil spill data from southern California, United States and worldwide sources are used in order to provide a sufficient sample. Local factors that may influence the frequency or magnitude of oil spills are, therefore, not fully taken into account. Other causal factors, such as ruptures of unburied pipelines, are possibly given too much weight given likely improvements in pipeline design for the southern California OCS.

- The available estimates of the costs of constructing deep-water pipelines are subject to change since the technology

is one that is new and rapidly developing. Furthermore, tanker charter rates are constantly fluctuating; current charter rates are used in the study.

- The production sites analyzed in this study are purely hypothetical and do not reflect knowledge of the actual location or magnitude of recoverable oil reserves. Therefore, marine transport and pipeline routes to shore and associated costs are also hypothetical.

The main body of this report is organized into the following 5 sections:

- Introduction
- Description of Transportation Alternatives
- Economic Analysis
- Oil Spill Risk Analysis
- Appendix.

I. INTRODUCTION

1. OBJECTIVES OF THE STUDY

It has been proposed that the Federal Government offer for lease approximately 1.55 million acres of the southern California Outer Continental Shelf (OCS) for the purpose of developing oil and gas reserves. The lease sale would be held in accordance with the Outer Continental Shelf Lands Act of 1953.

The objectives of this study were to develop, within the limitations of available data, a measure of the risk of oil spills from and an estimate of costs of alternative transport systems from OCS oil and gas fields to shoreside terminals and refineries. This was accomplished through a review of past oil spill statistics and analyses and application of the data to the specific conditions of southern California OCS. To assist in specifying these conditions, a series of strictly hypothetical scenarios were established. The selected production and gathering sites were not based on any knowledge of actual location of reserves.

2. DESCRIPTION OF THE LEASE SITES

As shown in Figure I-1, the three proposed lease sites are the Santa Barbara-Santa Catalina field, the Santa Rosa-Cortes (North) field, and Santa Rosa-Cortes (South) field.

(1) Santa Barbara-Santa Catalina Field

The center of this field is located 35 miles west-southwest of the City of Long Beach, California, and covers an area of 180,400 acres. The water depth in this area ranges from 125 to 500 fathoms.

The U.S. Geological Survey (USGS) has estimated the potential recoverable oil reserves in this tract to be from 67 to 219 million barrels of oil. Other studies by private agencies have estimated the reserves to be substantially higher;[1] however, the USGS findings will be used as the basis for this study.

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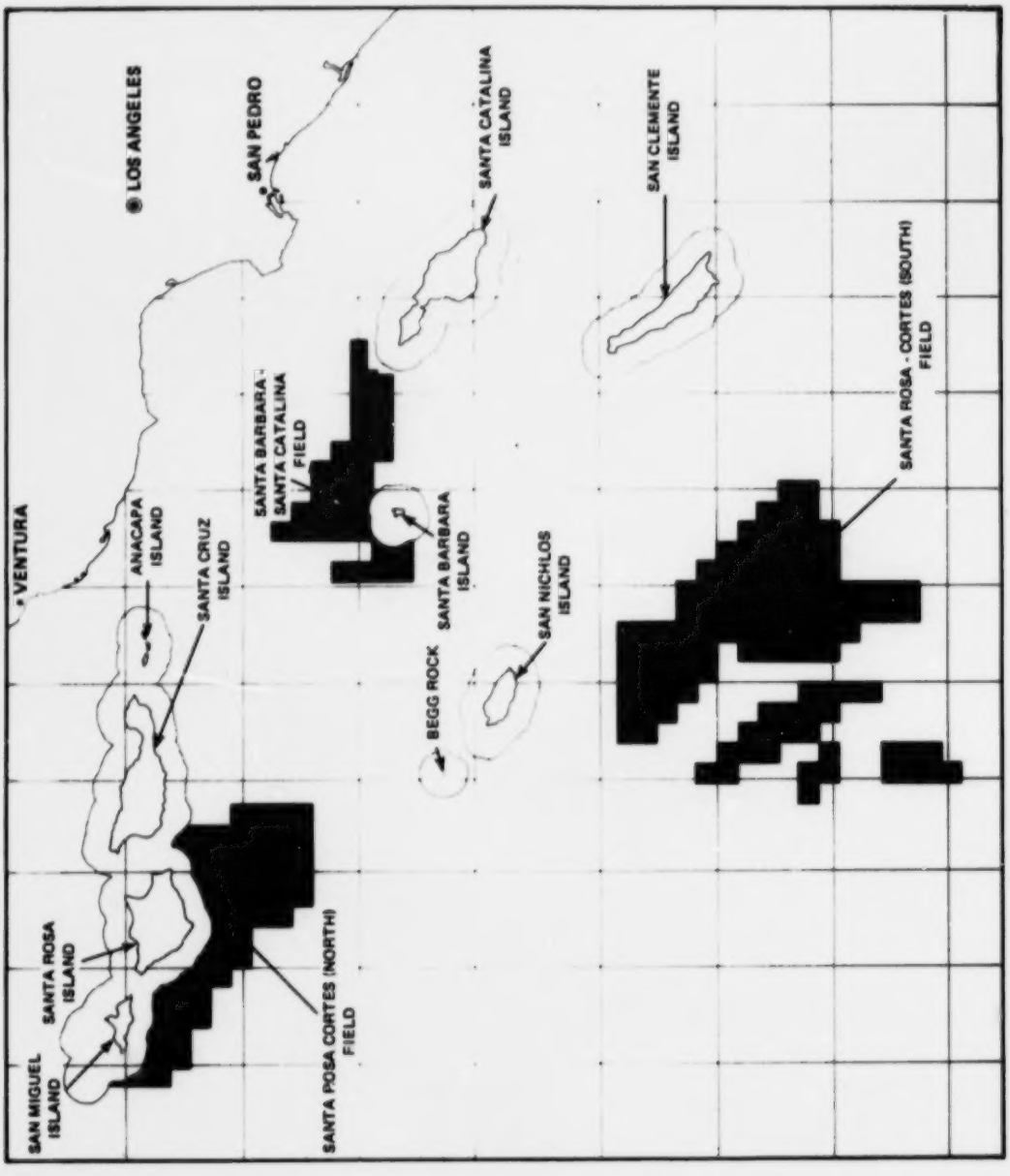
1 Western Oil and Gas Association (WOGA) has estimated that from 6 to 19 billion barrels of oil exists in the entire southern California OCS area.

FIGURE I-1
Proposed Southern California
Oil Lease Fields



(2) Santa Rosa-Cortes (North) Field

This field is located south of Santa Rosa, Santa Cruz, and San Miguel Islands and covers an area of 291,500 acres. The proposed lease fields are approximately 50 miles southwest of Ventura, California, in water depths which range from 50 to 700 fathoms.

USGS has estimated the amount of recoverable reserves in the proposed area to be from 242 to 431 barrels of oil.

(3) Santa Rosa-Cortes (South) Field

This area is located in the Cortes Basin, 83 miles west of the City of San Pedro, California, and covers a 639,400-acre area. The water depths within the boundaries of the proposed lease area range from 50 to over 700 fathoms. USGS estimates the amount of recoverable reserves are from 239 to 660 million barrels of oil.

3. IDENTIFICATION OF TRANSPORTATION ALTERNATIVES

Two primary transportation systems were considered for analysis in this study.

(1) Surface Marine Transportation Systems

Three alternative surface marine transport systems were considered for analysis:

- Self-propelled vessel: tanker
- Nonself-propelled vessel: barge
- ITB: integrated tug barge.

After a review of current state-of-the-art, it was determined that the integrated tug barge (ITB) system was not a practical alternative due primarily to their high cost of new construction and operation. Another factor against the ITB system is that recent attempts to integrate the barge and power unit at sea proved unsuccessful because of the different buoyancies of tug and barge. The nonself-propelled barge may be a useful alternative for close inshore operations, but its slow mode of operations and high risk of towline parting make it a less desirable alternative.

Overall the tanker system appears as the most desirable surface transport mode. It is further enhanced by the current availability of small- and medium-size tankers which would be adaptable to the type of dedicated tanker system envisioned for use in OCS development.

(2) Submarine Pipeline System

The second transport mode that was considered was the submarine pipeline. Pipelines have been in use for transporting crude oil overland for many decades. In comparison, the first U.S. offshore pipelines used for undersea transport of crude oil were laid in the Gulf of Mexico during the late 1940's. The use of offshore pipelines, while a relatively new technology, is nonetheless a rapidly growing one. Some of the advantages of offshore pipelines for transporting crude oil compared to surface transport systems include the following:

- They are highly reliable and relatively unaffected by surface weather conditions
- They are relatively inexpensive to operate
- They do not require storage facilities.

These advantages provide strong incentives for the use of offshore pipelines for transporting OCS crude oil.

Each of these alternatives is examined in detail in the following chapter of this report.

II. OIL TRANSPORT ALTERNATIVES FOR OFFSHORE SOUTHERN CALIFORNIA AND SELECTION OF HYPOTHETICAL TRANSPORT SYSTEMS

1. CRITERIA FOR TANKER SYSTEM DEFINITION

The use of a tanker system for transporting crude oil from the outer continental shelf will require several types of support facilities. The system will require some storage facility at the collection point to receive oil from the producing wells while the tanker is returning to port to off-load its cargo. For the purpose of this study, a one-ship system is assumed. The storage facility must be capable of receiving the amount of oil produced not only during transit and off-load time but also for any time the tanker is delayed due to weather or mechanical breakdown. Storage will avoid the costly procedures and revenue losses that occur when it is necessary to shut down a producing well.

The most economically feasible type of storage for California OCS is a floating barge type. Though the risk of oil spills from storage facilities was not within the scope of this study, it is assumed for purposes of this study that barges are an acceptable form of storage.

In addition to storage, mooring facilities for both the tanker and storage barge are required. There are several types of mooring systems which have been proposed for offshore use. They include: conventional buoy mooring (CBM), single point buoy mooring (SPM or monobuoy), single anchorage leg mooring (SALM), and manmade islands. Based on its relative low cost of installation and its lack of requirement for solid underwater trusses, the SPM was selected for the purposes of this study.

The SPM system consists of a flat, cylindrical buoy held in place by a series of anchors and chains. The buoy is connected to the gathering lines from the well via a submarine manifold and under-buoy bases. A turntable on top of the buoy carries the pipe from a central buoy swivel to the side of the buoy where it connects to a floating hose or hoses leading to the tanker or storage barge. The tanker or barge is made up to the buoy by means of two nylon hawsers running from the buoy turntable to the bow of the ship.

As stated previously, the tanker will be chartered from the existing fleet. It will therefore require conversion for use on SPM. This consists primarily of rigging the vessel to receive the floating hose from the buoy and the mooring bridle from the buoy swivel.

Offloading facilities or a receiving terminal are also required for tanker operations. Since the crude oil will be transported to onshore facilities in the greater Los Angeles area for refining, it is assumed that the tankers will use the existing terminal facilities located in that area.

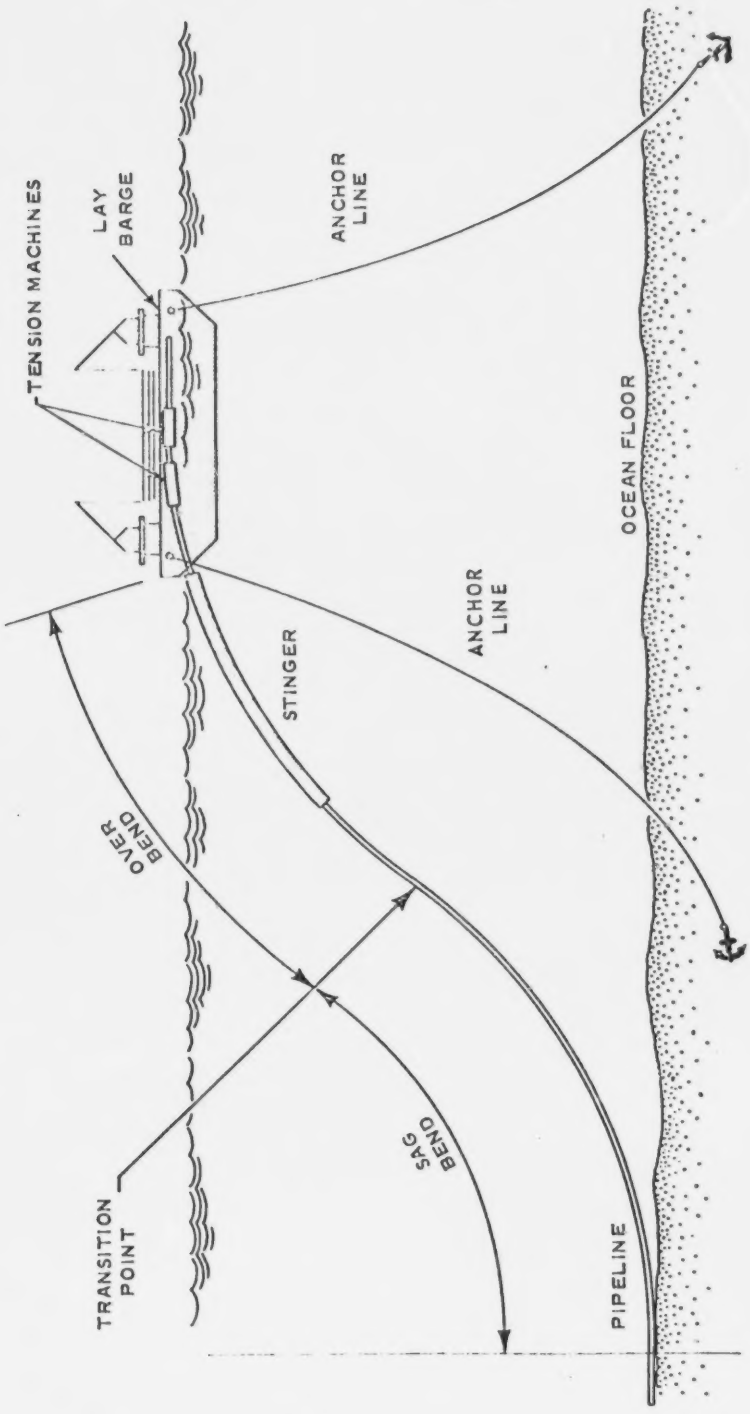
2. CRITERIA FOR PIPELINE SYSTEM DEFINITION

In order to provide a current perspective on the pipeline alternative two aspects of pipeline technology will be discussed in this section: current state-of-the-art for offshore pipelining, and laying procedures for offshore pipelines.

(1) Current State-of-the-Art for Offshore Pipelining

There are two principal obstacles to offshore pipelines: water depth and pipe size (diameter and wall thickness). The greater the depth, the thicker the pipe wall must be to resist the bending stresses placed on the pipe as shown in Figure II-1. The thicker walled pipe, however, adds weight and thus increases the bending stresses. Pipe diameter is a function of throughput. The larger finds of recoverable reserves will require larger pipe diameters which, in turn, add to the bending stresses on the pipe.

FIGURE II-1
Configuration of a Pipeline
During Laying Procedures



Small diameter pipes (less than 12 inches) were first laid in the United States in the shallow (20 feet) waters of the Gulf of Mexico in the late 1940's. Since that time, technological advances have increased both depth and pipe size capabilities. Larger diameter pipe, up to 44 inches, has been laid in 390 feet of water in the Gulf of Mexico. Saipem, an Italian company, has successfully laid a 12-inch line in 1,180 feet of water. The line is part of a working gas line that will join the Italian mainland, through the Straits of Messina, with the neighboring island of Sicily. Larger diameter pipes are presently restricted to the shallower depths. Plans are now underway, however, to construct a 103-mile long, 30-inch pipeline from Ninian Field to Shetland Island in the North Sea. The depths encountered along the proposed route will reach 500 feet.

The technological accomplishments described above represent significant advances in using offshore pipelines as a means of transporting OCS crude oil. However, the conditions existing in the southern California OCS offer new challenges to the designer and constructor of submarine pipelines. Additional capabilities will be required to meet the challenges of southern

California. Depths in this region approach 6,000 feet in some areas of the proposed lease fields while the amount of estimated reserves within these fields warrants the use of larger size (over 12 inch) pipelines.

To meet the challenges of southern California OCS, several projects have been undertaken by the petroleum industry assisted by the offshore constructors. Shell Pipeline Research and Development Laboratory is conducting investigations into pipelining in depths to 3,000 feet with investigation into pipelining in depths to 6,000 feet. The study is expected to cover a 30-month period and will focus on such topics as route selection, pipe specifications, and construction procedures. Repairs of pipelines in deep water will also be a part of the study.

Battelle Laboratories is also engaged in a study of deep water pipelining methods. The Battelle study will also concentrate on such things as wall thickness, diameter, tension, and properties of pipe materials. Successful completion of these projects will be a major step toward achieving the capability to pipeline in the depths and sizes of pipe required for transporting southern California crude oil.

During the course of this study, interviews were held with offshore construction firms and with major oil company representatives. he interviewees were very familiar with current and projected state-of-the-art for offshore pipeline technology. It was their unanimous opinion that pipelining in the depths experienced off the coast of southern California was technically feasible, given the time and resources to develop the laying techniques and resolve other technical problems involved.

(2) Pipeline Laying Procedures

The most common and accepted method of offshore pipelining is the use of the lay barge. A typical lay barge configuration is shown in Figure II-1. Pipe is normally delivered to the lay barge in 40-foot sections, although some new lay barges are capable of handling double (80-foot) sections of pipe. The barge is divided into several stations. At the first station, the new section is aligned to the previous installed length and prepared for welding. Depending on the wall thickness of the pipe, several weld beads are required to prevent cracking of the weld. In the case of unusually thick walled pipe, it is necessary to preheat the sections prior to welding. When the two sections have been welded, they are then X-rayed to establish the integrity of the welds.

Once it is established that the welds are satisfactory, a protective corrosive coating of hot asphalt known as a "field joint" is applied. The entire pipe section is then coated with a preservative and a predetermined thickness of concrete mesh. The concrete serves the dual purpose of providing negative buoyancy during installation and stability against wave action after the line is installed and lying on the ocean bottom.

When the above process is completed, the barge, which is being held in position by 6 to 8 anchors, is moved ahead and the new section of pipe is lowered off the stern of the barge. To support the pipe and reduce the risk of buckling due to excessive bending stresses, a device known as a "stinger" extends from the stern of the barge and supports the pipe as it transcends to the bottom or to a point where the pipe is capable of self-support. It is obvious, therefore, that pipelaying becomes increasingly complex as water depth increases.

In depths where stinger support of the pipe is not practical, the use of a tensioning device enables pipelines to be constructed in deeper waters. By applying axial tensile force, bending stress is controlled and the risk of buckling reduced.

The ability to hold the barged in a fixed position during laying operations is an important factor. It is essential to avoid any back motion of the barge because increases in the sag-bend of the pipeline will contribute to pipe buckling. The barges must be equipped with sufficient anchor chain and wire rope for the vessel to be held in place or moved without resetting the anchors. Winches must also be provided for repositioning the barge.

The problems associated with offshore pipelining are increased as depth increases. As the pipe transcends into the deeper waters, the sag-bend problem also increases the requirement for thicker walled pipe. The thicker pipe requires additional tension forces to help support it. Deeper waters also make barge positioning more difficult, but technology is responding to these problems with two new developments. The "articulated stinger" was developed for both deep and shallow water pipelaying. This type of stinger, which has a number of variations, is composed of individual sections hinged together. The hinged sections allow for easy changes in stinger radius; moreover, sections can be added or removed for different job requirements. To provide for better tension control, a "dynamic tensioning" mechanism has been developed. The

device consists of wheels or tracks that grip the pipe with a high force transverse to the pipe's longitudinal axis. Torque is then applied to the wheels (or tracks) placing a tensional force in the form of friction against the outer coating of the pipe. A control system maintains a constant tension force by either "paying out" or "hauling in" pipe as the barge surges in any direction.

With increased water depths, anchor lines become larger and longer with corresponding increases in winch sizes. Dynamic positioning will contribute to eliminating positioning problems in deep waters. The system incorporates the use of thrusters to hold the barge on station. A similar, though not as complex a system, is currently in use on board drill ships. The drill ship is required only to remain in a fixed position over the drill site. The lay barge must be capable of moving in all directions relative to pipe tension.

Once the pipeline is in place, it must be protected from movement and subsequent chafing due to external forces. These external forces can be underwater currents or turbidity as well as mechanical objects such as anchors, fishing tackle, and even sunken vessels. Turbidity is the massive movement of particles

of sediment down the sides of a submarine slope or canyon. This movement produces underwater currents at speeds up to 60 miles per hour. Turbidity forces have been known to cause breaks in submarine cables. To counter these forces, the pipeline is coated with concrete mesh. The added weight of the concrete also provides stability and protects the pipe from external damage.

Pipelines are often buried 3 to 10 feet to protect them from damage due to external forces. In the past this has been accomplished in relatively shallow depths, approximately 200 feet or less, by blasting, with charges set by divers or by use of a "bury barge." The barge is equipped with high pressure water pumps providing jetting action to cut the sea floor beneath the pipe. The jet nozzles are mounted on a sled which straddles the pipe after it is laid on the sea floor.

Recently the Santa Fe International Corporation placed an order with a Dutch shipyard for a deep water pipeline bury barge with capabilities of operating in depths up to 1,000 feet. The barge, which is scheduled for delivery in mid-1976, will be able to excavate a trench 7 feet deep on a single pass under favorable soil conditions.

The technical problems associated with offshore pipelining, even at the shallower depths, have been described in the preceding pages. The complexities of these problems as depths increase beyond the 200-fathom curve are significant barriers that must be overcome through technological development. Considering these problems as well as the current state-of-the-art, pipelines are believed to be a technically feasible transport alternative for southern California OCS oil. Since production from OCS oil wells is 3 to 8 years from actual lease sale, it is believed there is sufficient time to develop the technology to accomplish deep water pipelining.

3. SELECTION OF HYPOTHETICAL PRODUCTION SITES AND TRANSPORT SYSTEMS

To assist in assessing comparative risks of oil spills from surface vessels and submarine pipelines, hypothetical production sites and transport systems were selected from the proposed southern California lease areas. The areas were examined, on the basis of depth and geographic location, for the selection of a gathering point. Since either surface marine or submarine pipeline would use the same gathering point, only the system carrying oil from the gathering point to the onshore receiving facility was determined. The scenarios for the hypothetical transport systems assumed that the number of wells and the production rates were the same for both transport alternatives.

(1) Santa Rosa-Cortes (North) Field

The transport routes for the Santa Rosa-Cortes (north) field are shown on Figure II-2. The gathering point was selected primarily for its relatively shallow depth: 60 fathoms as compared to depths as great as 800 fathoms in other areas of the field. A second consideration was its position relative to the receiving point, Ventura, California. Ventura was selected as the receiving point on the basis of its existing facilities for processing crude petroleum. Both the water route and pipeline route in Figure II-2 indicate a 3-mile offset from Santa Cruz Island. The 3-mile offset provides the protection of distance to the islands in the event of an oil spill. Figure II-3 displays a profile of water depth along the pipeline route with a maximum depth of approximately 2,500 feet. Pipelining in these depths is more difficult and costly than the alternate routes shown on Figure II-4. The alternate routes, however, will not afford the islands the protection of distance in the event of an oil spill. Figures II-5, II-6, and II-7 relate the depth profiles of the three alternative routes. A comparison of profiles indicates that the routes that do not require a 3-mile offset will facilitate pipeline construction and have a beneficial effect on costs. These benefits result from the fact that the maximum depths encountered

FIGURE II-2
Transport System Routes for
Santa Rosa-Cortes (North)

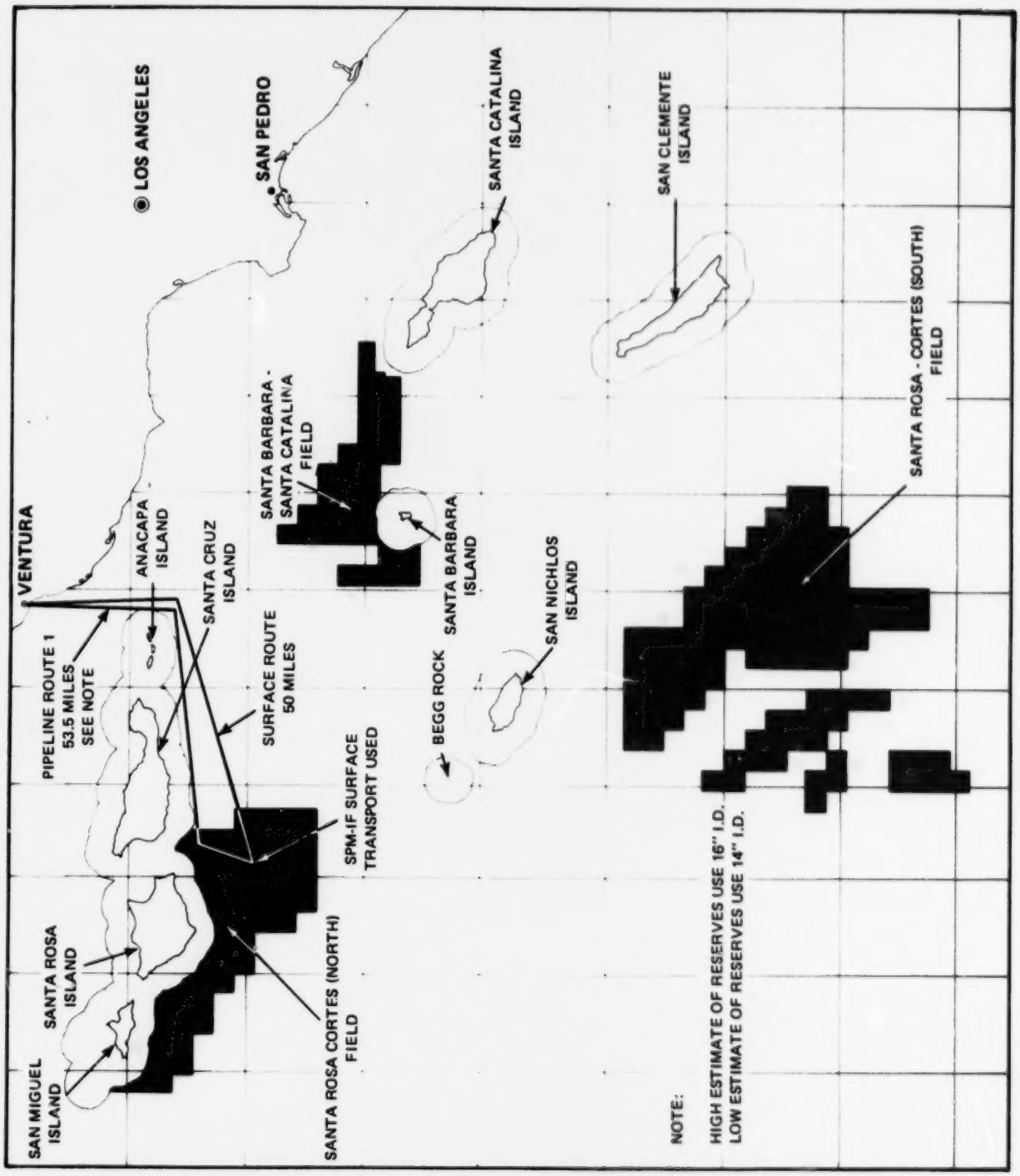


FIGURE II-3
Depth Profiles
Santa Rosa-Cortes (North)
Pipeline Route 1

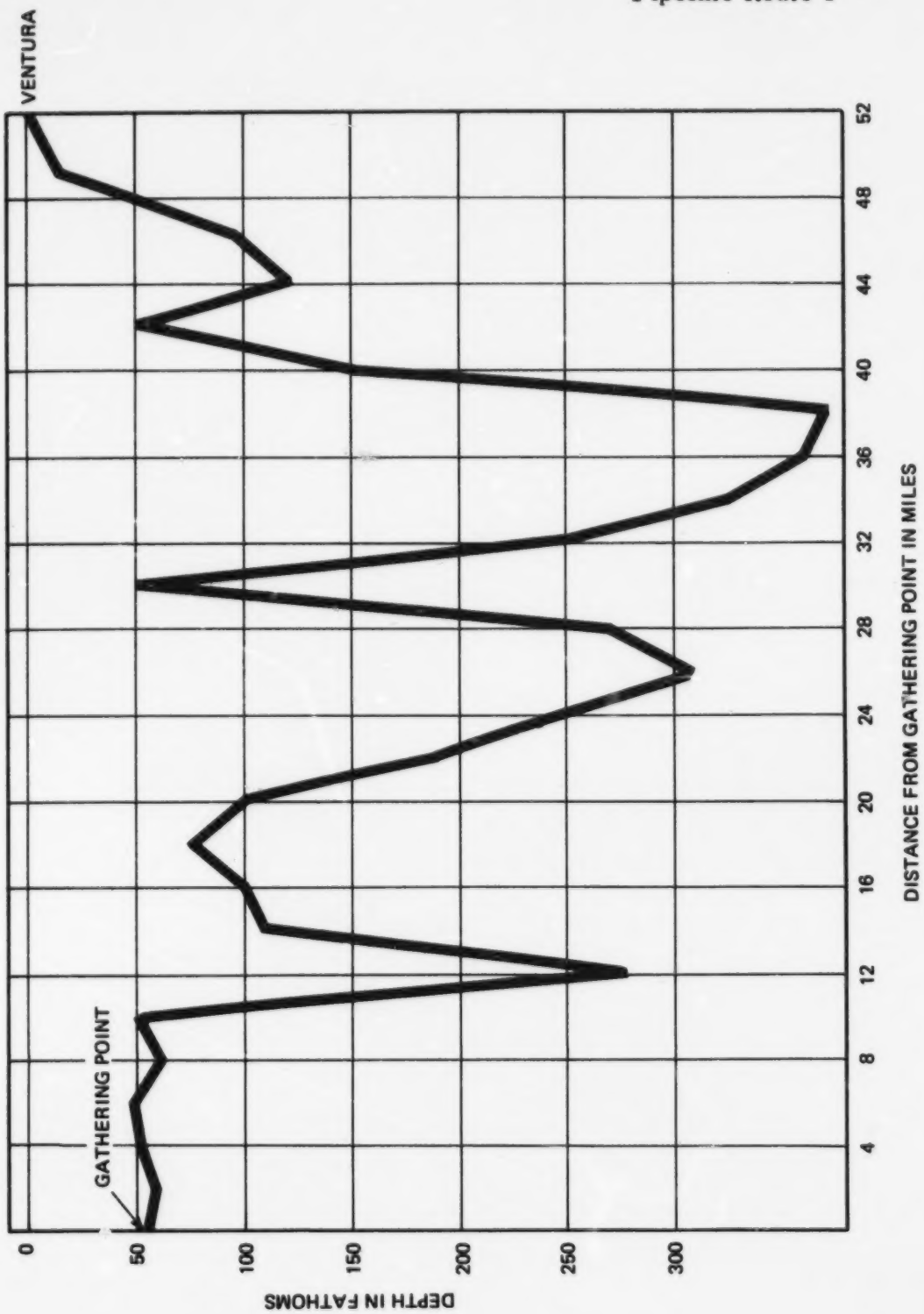


FIGURE II-4
Alternate Pipeline Routes for
Santa Rosa-Cortes (North)
Field

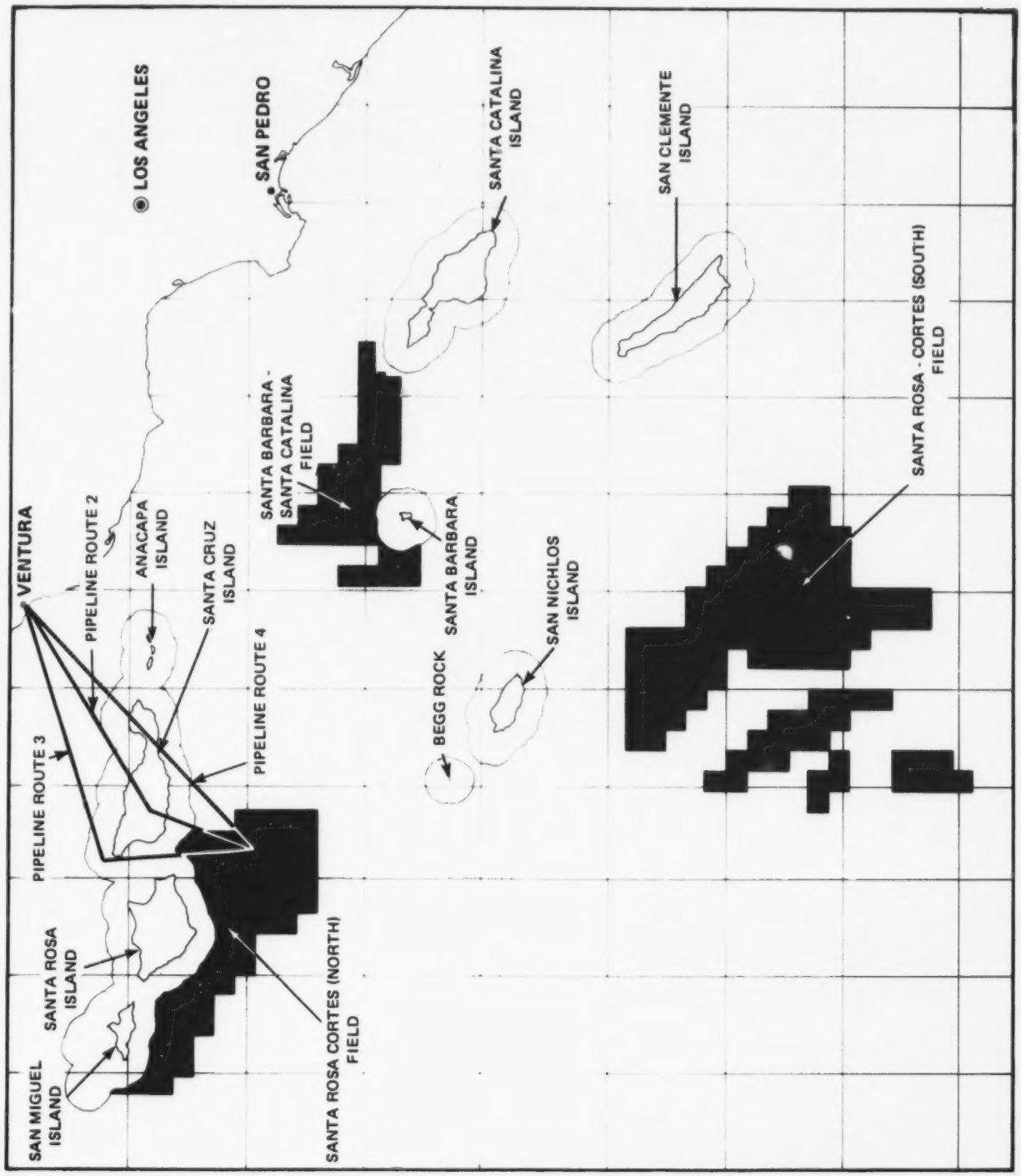


FIGURE II-5
Depth Profiles
Santa Rosa-Cortes (North)
(Pipeline Route 2)

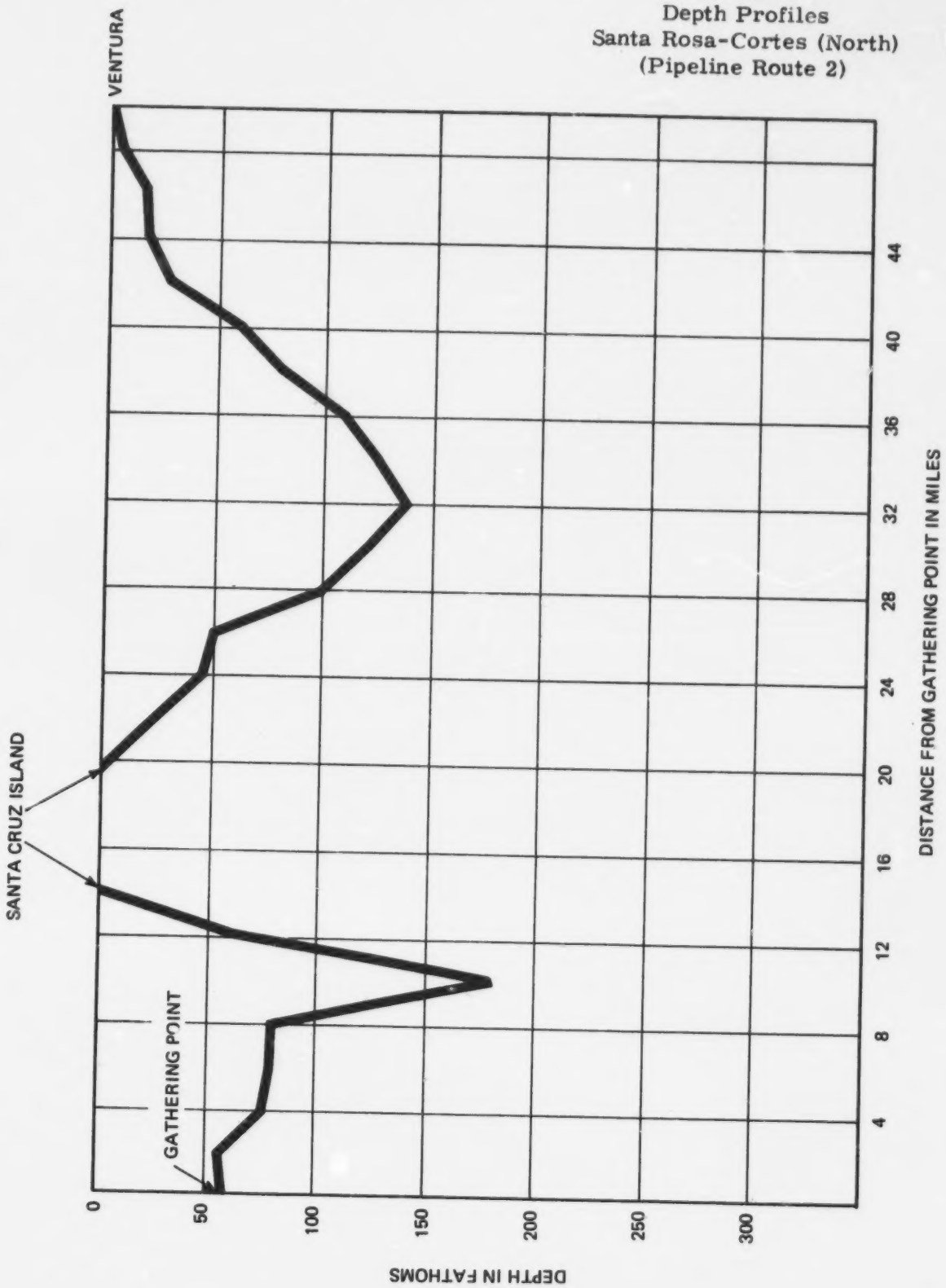


FIGURE II-6
Depth Profiles
Santa Rosa-Cortes (North)
Pipeline Route 3

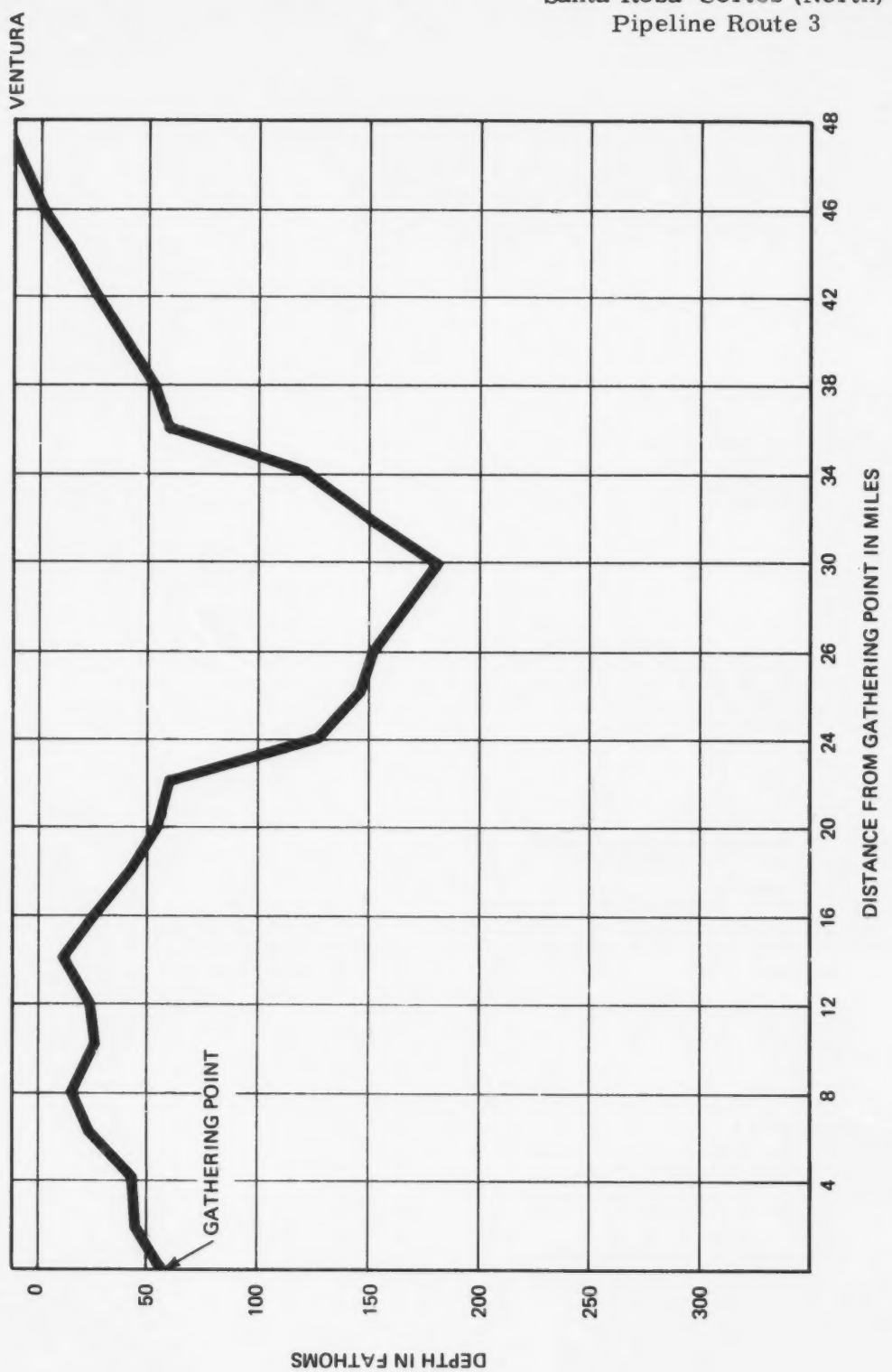
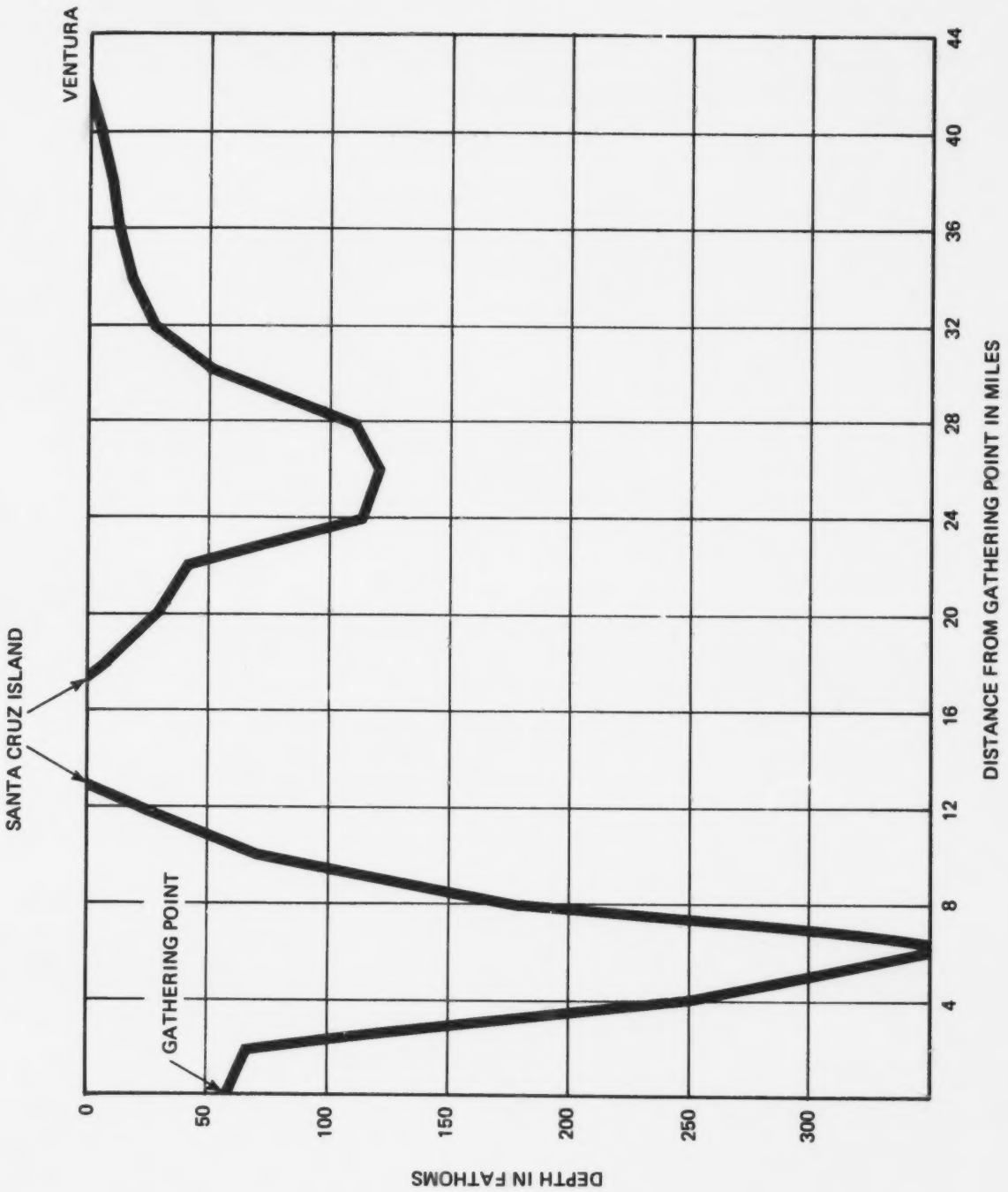


FIGURE II-7
Depth Profiles
Santa Rosa-Cortes (North)
Pipeline Route 4



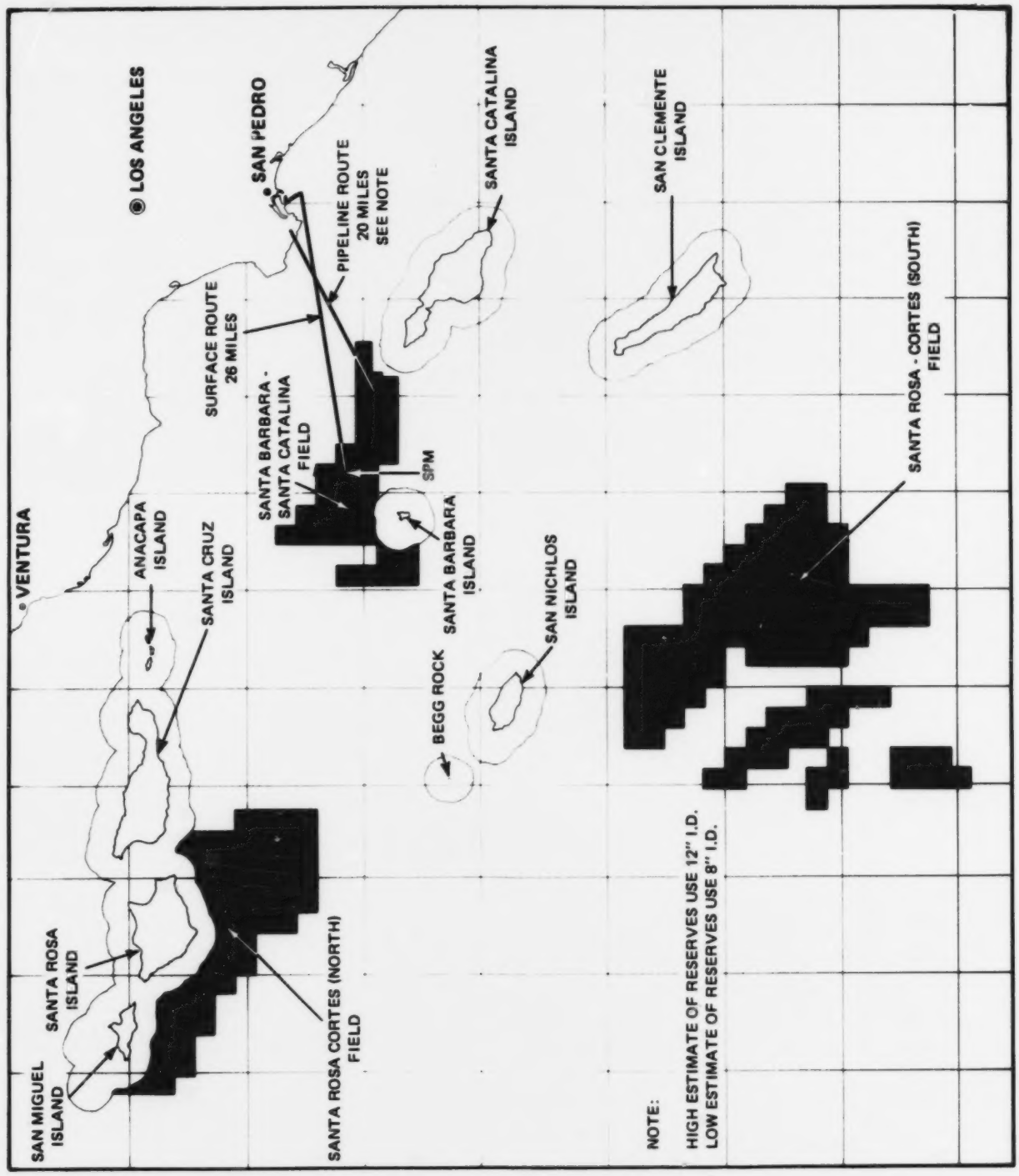
along all three alternative routes are less than those depths encountered in going around the island.

General practice is to bury pipelines where depths are less than 2,000 feet. Because of the deep conditions along all the pipeline routes shown in Figures II-2 and II-4 (maximum is 450 fathoms), pipeline burial would be required only where it approaches the shore or in shipping lanes and anchorage areas. Geological conditions along the pipeline routes consist primarily of sedimentary rock formations covered by .20 to 100 feet of silty sand and are favorable for burial. Since pipeline burial is normally no more than 10 feet below the ocean floor, no difficulty in pipeline burial is anticipated.

(2) Santa Barbara-Santa Catalina Field

Figure II-8 shows the proposed pipeline and water routes for the Santa Barbara-Santa Catalina field. The routes are the most direct to the selected receiving point at San Pedro, California. The gathering point for the surface system is different from the pipeline gathering point. This is due to the desire to keep the mooring systems in as shallow water as possible to facilitate installation and to reduce costs. The gathering point for the pipeline is located as near to the receiving point as possible and within the area where production will take place.

FIGURE II-8
Transport System Routes for
Santa Barbara-Santa Catalina Field



Geological conditions along the pipeline route consist primarily of sedimentary rock with a small area of volcanic deposits northeast of Santa Catalina Island. The rock deposits are covered by layers of mud and silty sand. In view of the depth contours shown in Figure II-9, pipeline burial would probably be required only within a 2- to 3-mile distance offshore where the pipeline is brought ashore. An option to be considered would be to bury the pipeline where it crosses the Santa Barbara Shipping Channel. This would be very costly since depths in this area exceed 2,400 feet, and no present equipment is capable of burying pipe at this depth.

(3) Santa Rosa-Cortes (South) Field

The Santa Rosa-Cortes (south) field is located in an area of extremely deep water with depths exceeding 4,200 feet in some parts. Figure II-10 shows a direct surface route to the closest onshore facilities in San Pedro. A parallel pipeline route, however, would encounter depths of nearly 6,000 feet. A more shallow, though considerably larger, pipeline route is also shown on Figure II-10. The maximum depth encountered along this route is 1,500 feet. The route would carry the oil to the facilities at Ventura instead of San Pedro. By installing

FIGURE II-9
Depth Profiles
Santa Barbara-Santa Catalina
Pipeline Route

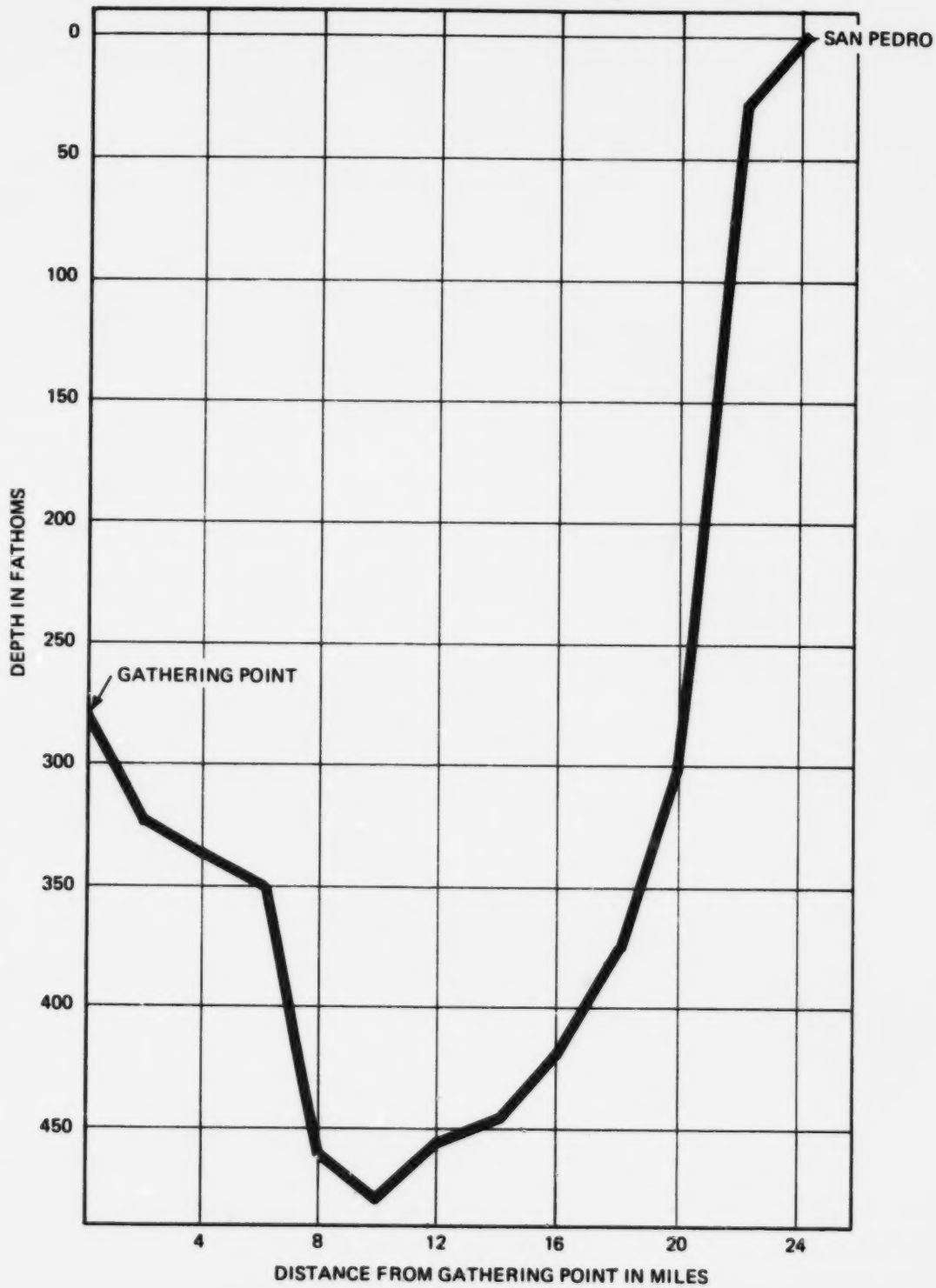
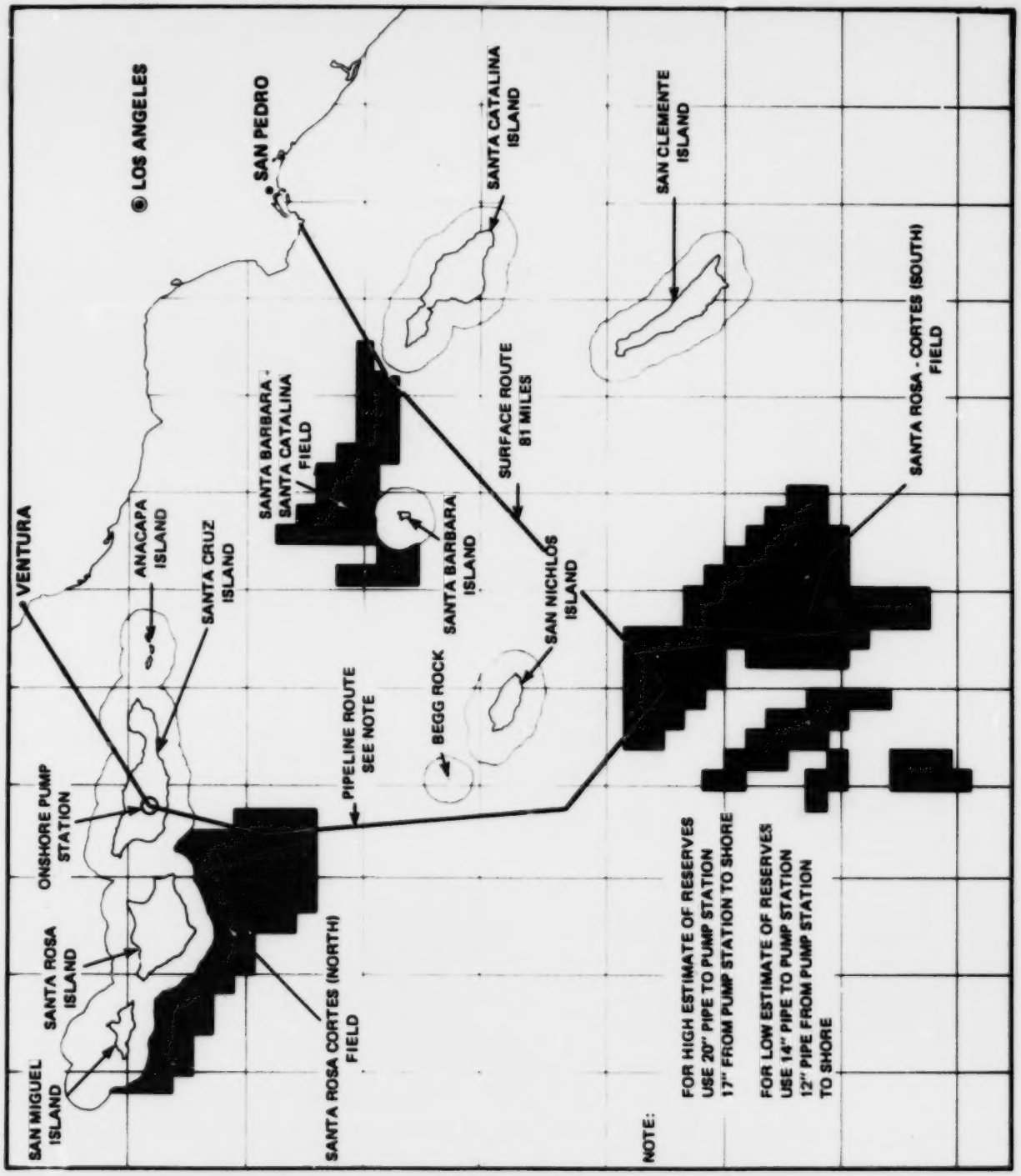
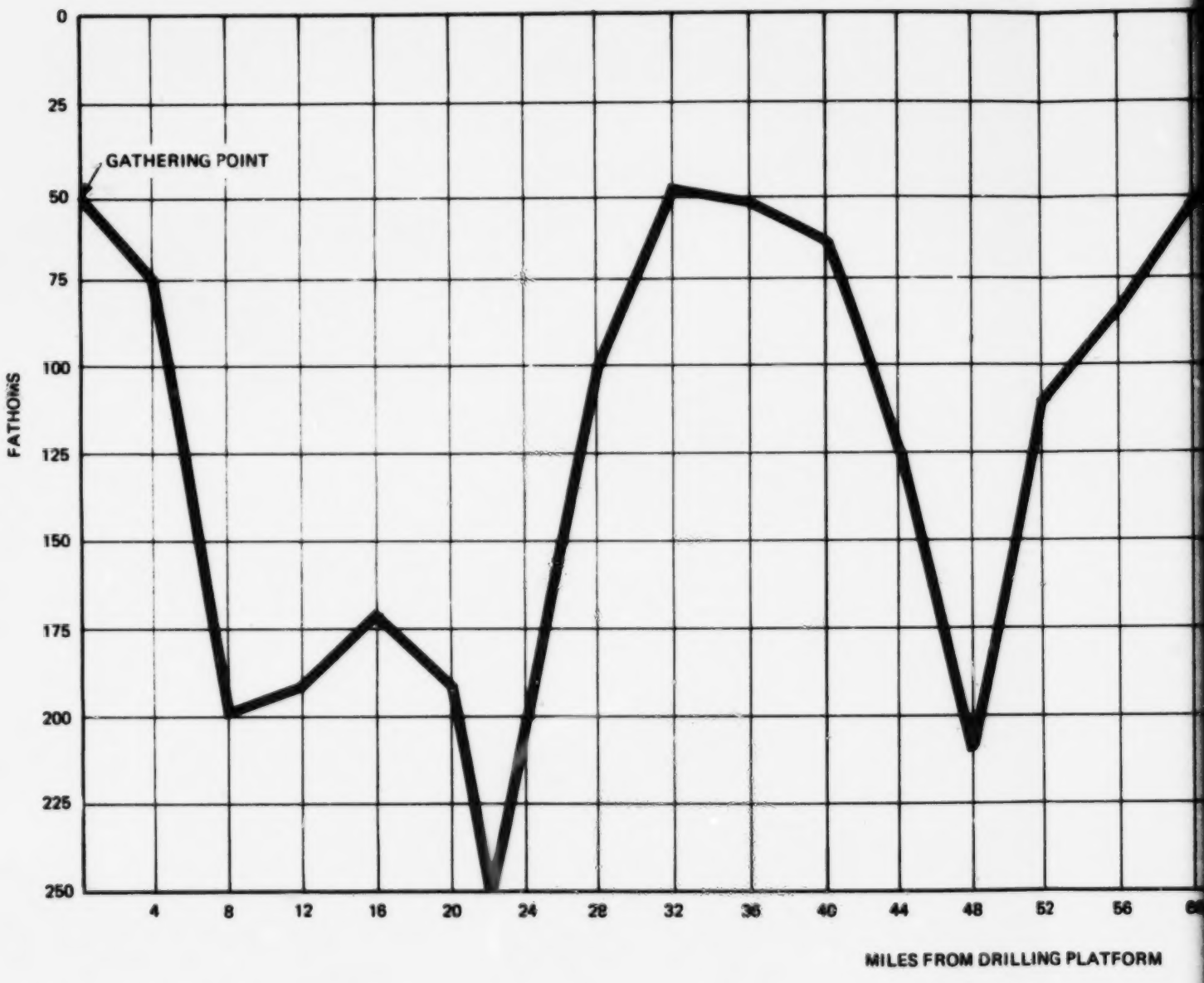


FIGURE II-10
Transport Systems Routes for
Santa Rosa-Cortes (South) Field

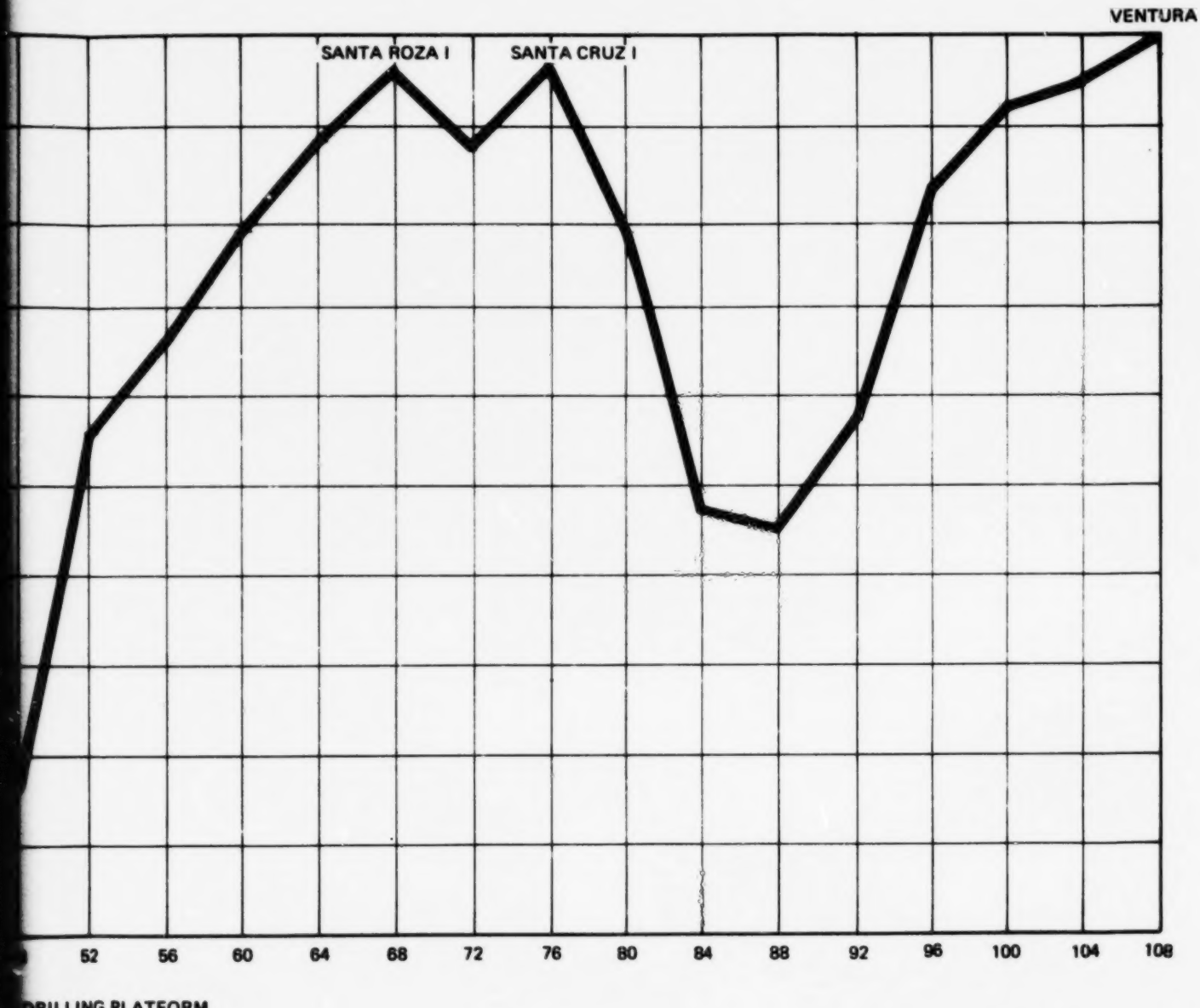

SAN MIGUEL ISLAND
SANTA ROSA ISLAND
ONSHORE PUMP STATION
VENTURA
LOS ANGELES
SAN PEDRO
ANACAPA ISLAND
SANTA CRUZ ISLAND
SANTA BARBARA - SANTA CATALINA FIELD
SANTA BARBARA ISLAND
SANTA CATALINA ISLAND
SAN CLEMENTE ISLAND
SURFACE ROUTE 81 MILES
SAN NICHLOS ISLAND
BEGG ROCK
PIPELINE ROUTE SEE NOTE
SANTA ROSA CORTES (NORTH) FIELD
SANTA ROSA - CORTES (SOUTH) FIELD
NOTE:
FOR HIGH ESTIMATE OF RESERVES USE 20" PIPE TO PUMP STATION 17" FROM PUMP STATION TO SHORE
FOR LOW ESTIMATE OF RESERVES USE 14" PIPE TO PUMP STATION 12" PIPE FROM PUMP STATION TO SHORE

a pump station along this longer route, pipe of reduced diameter can be used. This will facilitate construction and reduce costs. Referring to Figure II-10, the pump station is sited on Santa Rosa Island. Should there be a requirement or desire to keep the pipeline off the island, an alternate route with a pump station located offshore is shown in Figure II-11. As shown in Figure II-12, depths along the pipeline route indicate pipeline burial would be practical only where the pipeline is brought ashore either on the island or on the mainland. Geological conditions in these areas are favorable for burial, consisting mostly of sedimentary rock covered by sand and silt.


0
25
50
75
100
125
150
175
200
225
250
FATHOMS
GATHERING POINT
4
8
12
16
20
24
28
32
36
40
44
48
52
56
MILES FROM DRILLING PLATFORM

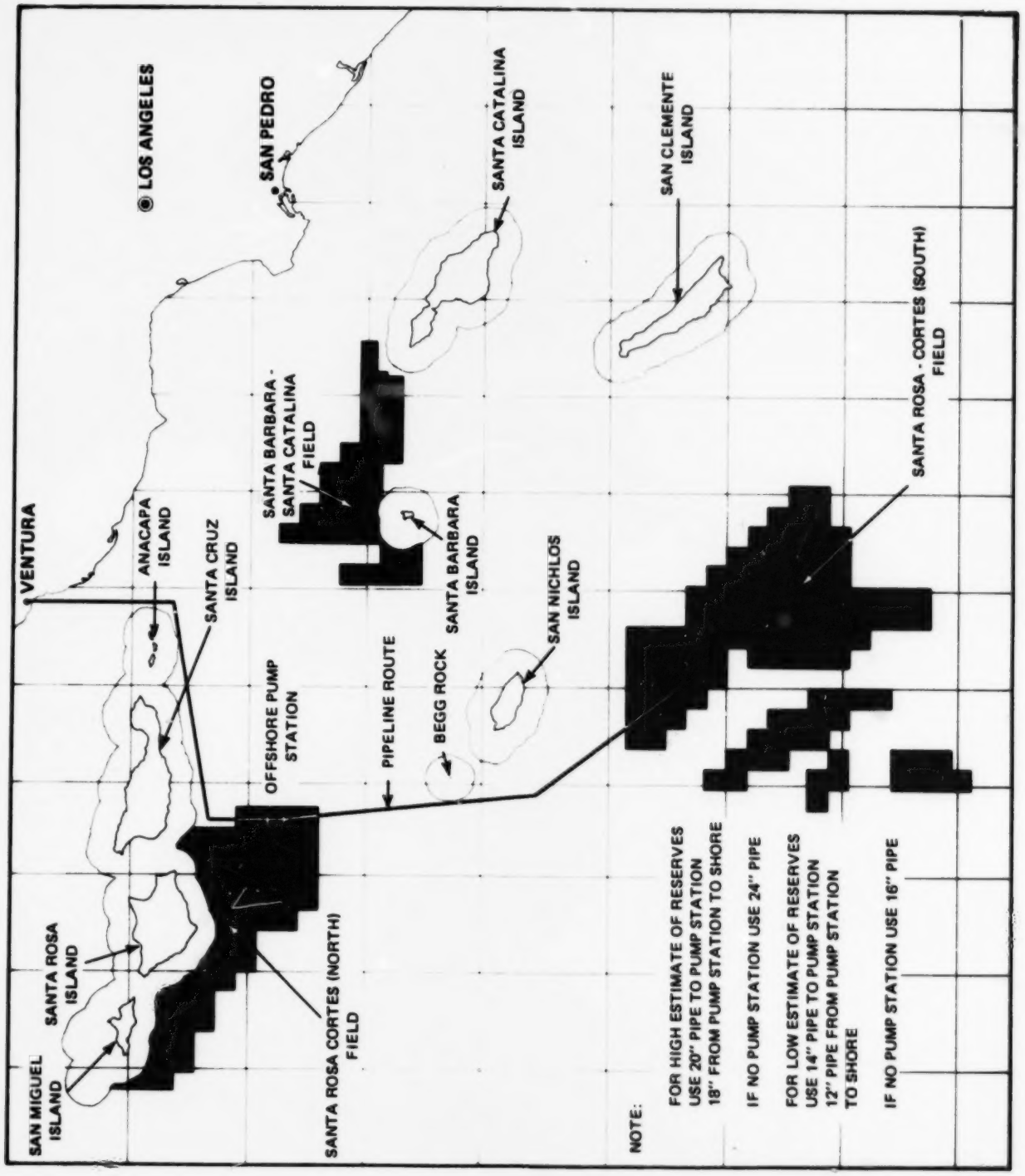
A

FIGURE II-11
Depth Profiles
Santa-Rosa-Cortes (South)
Pipeline Route



B

FIGURE II-12
Alternate Pipeline Route for
Santa Rosa-Cortes (South)


LOS ANGELES
SAN PEDRO
SANTA CATALINA ISLAND
SAN CLEMENTE ISLAND
VENTURA
ANACAPA ISLAND
SANTA CRUZ ISLAND
SANTA BARBARA - SANTA CATALINA FIELD
SANTA BARBARA ISLAND
SAN NICHLOS ISLAND
SANTA ROSA - CORTES (SOUTH) FIELD
OFFSHORE PUMP STATION
PIPELINE ROUTE
BEGG ROCK
SAN MIGUEL ISLAND
SANTA ROSA ISLAND
SANTA ROSA CORTES (NORTH) FIELD
NOTE:
FOR HIGH ESTIMATE OF RESERVES USE 20" PIPE TO PUMP STATION 18" FROM PUMP STATION TO SHORE
IF NO PUMP STATION USE 24" PIPE
FOR LOW ESTIMATE OF RESERVES USE 14" PIPE TO PUMP STATION 12" PIPE FROM PUMP STATION TO SHORE
IF NO PUMP STATION USE 16" PIPE

III. ECONOMIC ANALYSIS

The economics of outer continental shelf (OCS) oil transport systems is dependent upon three conditions:

- Amount of recoverable reserves
- Distance from the collection point to onshore terminal
- Depth of water in which the reserves lie and depths along the route from the collection point to onshore terminal.

The costs of both the surface marine and the pipeline systems will be influenced by the above factors.

The amount of recoverable reserves will determine the production rate of the wells which, in turn, will affect the:

- Capacity of the tanker required
- Capacity of storage facilities required
- Diameter of pipeline required.

The distance from collection point to the onshore terminal will determine:

- Fuel consumption and size of the required tanker
- Length of the pipeline system.

Water depth will have an effect on:

- Installation costs of mooring systems
- Material and construction costs for the pipeline.

The installation costs for mooring facilities increase substantially with depth since the working time for divers setting the anchoring devices is reduced to less than 30 minutes per dive as depths approach 1,000 feet. This will require the use of a submersible vehicle in those depths where the use of divers is prohibited.

As outlined in Chapter II, pipelines require thicker walls as depths increase, thus causing increased material costs. More sophisticated and expensive pipelaying equipment will also be required in deeper waters, and will therefore increase installation costs.

Capital costs for the tanker system include costs for converting the tanker for single point mooring operation and for acquiring the required storage barge and mooring systems for both barge and tanker.

Operating costs for the tanker system are comprised of fuel costs and charter hire costs, including manning and upkeep, crewing, provisioning, and maintenance and repair.

In the case of the pipeline, capital costs are those incurred when constructing the line. Operational costs primarily include maintenance and monitoring expenses.

The methodology employed in this economic analysis is outlined in Appendix A.

Tables III-1 through III-6 display the results of the economic analysis of the transport systems proposed from the hypothetical scenarios outlined in Chapter II. The costs are based on data obtained from maritime reports and publications, pipeline construction manuals, and interviews with marine transportation analysts and pipeline designers. Although inflation factors were considered when calculating life-cycle costs, such items as charter and fuel costs will fluctuate with factors such as the world market for energy carriers.

As stated in Chapter II, considerable technological problems must be overcome to enable pipelines to be laid in waters beyond the 200-fathom mark. Since actual pipelaying in these depths has yet to be accomplished, the costs must be considered as estimates, not absolute values.

Table III-1
Economic Analysis
Santa Rosa-Cortes (North) Field

Estimated Reserves	Transport System	Capital Costs ($)*	Operating Costs ($/yr) †	Life Cycle Costs ($) ‡	Per Barrel Cost ($)
USGS Low Estimate: 242,000,000 bbl	1 - 21,500 DWT Tanker 2 - SPM Systems 1 - 30,600 DWT Barge (Storage)	22,870,000	2,305,000	53,216,000	0.220
	1 - 14" I.D. Pipe 53.5 Miles	45,500,000	1,820,000	68,181,000	0.280
USGS High Estimate: 431,000,000 bbl	1 - 38,000 DWT Tanker 2 - SPM Systems 1 - 54,500 DWT Barge (Storage)	27,650,000	4,039,247	80,034,000	0.190
	1 - 16" I.D. Pipe 53.3 Miles	50,700,000	2,028,000	75,973,000	0.180

* For tanker system, assume tankers available from existing fleet, capital costs for ship conversion to single point mooring system, installation of mooring system, and acquisition of barge for storage. For pipeline system, costs are installation including burial where required.

† For tanker charter, costs plus fuel costs; for pipeline, maintenance and operation.

‡ 20-year field life and amortization; discount rate=10%; interest rate=10%; fuel cost inflation rate=7%; other operating cost inflation rate=5%

Table III-2
Economic Analysis
Alternate Pipeline Routes, Santa Rosa-Cortes (North) Field

Estimated Reserves	Transport System	Capital Costs ($)*	Operating Costs ($/yr)†	Life Cycle Costs ($)‡	Per Barrel Cost ($)
USGS Low Estimate: 242,000,000 bbl	Pipeline Route 1	45,500,000	1,820,000	68,181,000	0.280
	Pipeline Route 2	19,762,369	790,495	29,614,000	0.120
	Pipeline Route 3	26,929,890	1,077,196	40,354,000	0.170
	Pipeline Route 4	21,245,175	21849,807	31,836,000	0.130
USGS High Estimate: 431,000,000 bbl	Pipeline Route 1	56,700,000	2,028,000	75,973,000	0.180
	Pipeline Route 2	21,761,098	870,444	32,609,000	0.080
	Pipeline Route 3	30,471,000	1,218,840	45,660,000	0.110
	Pipeline Route 4	26,002,000	1,040,080	38,964,000	0.090

* For tanker system, assume tankers available from existing fleet, capital costs for ship conversion to single point mooring system, installation of mooring system, and acquisition of barge for storage. For pipeline system, costs are installation including burial where required.

† For tankers charter, costs plus fuel costs; for pipeline, maintenance and operation.

‡ 20-year field life and amortization; discount rate=10%; interest rate=10%; fuel cost inflation rate=7%; other operating cost inflation rate=5%.

NOTES:

Pipeline Route 1: Deep water route around island, staying offshore 3 miles
Pipeline Route 2: Shallow water route across Santa Cruz Island
Pipeline Route 3: Shallow water route through Santa Cruz Channel
Pipeline Route 4: Direct route across Santa Cruz Island to Ventura

Table III-3
Economic Analysis
Santa Barbara-Santa Catalina Field

Estimated Reserves	Transport System	Capital Costs ($)*	Operating Costs ($/yr)†	Life Cycle Costs ($)‡	Per Barrel Costs ($)
USGS Low Estimate: 67,000,000 bbl	1 - 16,000 DWT Tanker 1 - SPM 1 - 8,700 DWT Barge (Storage)	18,490,000	1,658,333	40,347,000	0.600
	1 - 8" I.D. Pipe 20 Miles	10,600,000	425,000	15,833,000	2.237
USGS High Estimate: 219,000,000 bbl	1 - 17,000 DWT Tanker 1 - SPM 1 - 28,000 DWT Barge (Storage)	22,290,000	1,848,711	46,346,000	0.210
	1 - 12" I.D. Pipe 20 Miles	15,600,000	624,000	23,400,000	0.107

* For tanker system, assume tankers available from existing fleet, capital costs for ship conversion to single point mooring system, installation of mooring system, and acquisition of barge for storage. For pipeline system, costs are installation including burial where required.

† For tankers charter, costs plus fuel costs; for pipeline, maintenance and operation.

‡ 20-year field life and amortization; discount rate=10%; interest rate=10%; fuel cost inflation rate=7%; other operating cost inflation rate=5%.

Table III-4
Economic Analysis
Santa Barbara-Santa Catalina

Estimated Reserves	Transport System	Capital Costs ($)*	Operating Costs ($/yr)†	Life Cycle Costs ($)‡	Per Barrel Costs ($)
USGS Low Estimate: 67,000,000 bbl	1 - 3500-hp Tug 1 - 8500 T Barge 2 - 2500 T Barges 2 - SPM Systems	2,000,000 1,700,000 1,000,000 16,000,000	425,000	24,499,000	0.366

* For tanker system, assume tankers available from existing fleet, capital costs for ship conversion to single point mooring system, installation of mooring system, and acquisition of barge for storage. For pipeline system, costs are installation including burial where required.

† For tankers charter, costs plus fuel costs; for pipeline, maintenance and operation.

‡ 20-year field life and amortization; discount rate=10%; interest rate=10%; fuel cost inflation rate=7%; other operating cost inflation rate=5%.

Table III-5
Economic Analysis
Santa Rosa-Cortes (South) Field

Estimated Reserves	Transport System	Capital Costs ($)*	Operating Costs ($/yr)	Life Cycle Costs ($)	Per Barrel Costs ($)
USGS Low Estimate: 239,000,000 bbl	1 - 26,000 T Tanker 2 - SPM Systems 1 - 40,000 T Barge (Storage)	24,808,000	3,207,944	67,259,000	0.280
	Pipeline (1)	89,360,000	3,574,000	133,910,000	0.560
	Pipeline (2)	124,350,000	4,974,000	186,337,000	0.780
	Pipeline (3)	119,650,000	4,746,000	178,796,000	0.750

* For tanker system, assume tankers available from existing fleet, capital costs for ship conversion to single point mooring system, installation of mooring system, and acquisition of barge for storage. For pipeline system, costs are installation including burial where required.

† For tankers charter, costs plus fuel costs; for pipeline, maintenance and operation.

‡ 20-year field life and amortization; discount rate=10%; interest rate=10%; fuel cost inflation rate=7%; other operating cost inflation rate=5%.

NOTES:

Pipeline (1) From gathering station to onshore pump station, 78 miles, 14-inch I. D., 1-inch wall; from pump station to shore, 32 miles, 12-inch I. D., 3/4-inch wall.

Pipeline (2) From gathering station to offshore pump station 70 miles, 14-inch I. D., 1-inch wall; from offshore pump station to shore 53 miles, 12-inch I. D., 1-inch wall.

Pipeline (3) From gathering station to shore (no pump station) 118 miles, 16-inch I. D., 1-inch wall.

Table III-6
Economic Analysis
Santa Rosa-Cortes (South) Field

Estimated Reserves	Transport System	Capital Costs ($)*	Operating Costs ($/yr)†	Life Cycle Costs ($)‡	Per Barrel Costs ($)
USGS HIGH Estimate: 660,000,000 bbl	1 - 71,000 DWT Tanker 2 - SPM Systems 1 - 55,500 DWT Barge (Storage)	38,877,000	7,549,753	136,794,000	0.210
	Pipeline (1)	144,230,000	5,770,000	216,137,000	0.330
	Pipeline (2)	182,660,000	7,306,000	273,714,000	0.410
	Pipeline (3)	262,025,000	10,418,000	392,641,000	0.595

* For tanker system, assume tankers available from existing fleet, capital costs for ship conversion to single point mooring system, installation of mooring system, and acquisition of barge for storage. For pipeline system, costs are installation including burial where required.

† For tankers charter, costs plus fuel costs; for pipeline, maintenance and operation.

‡ 20-year field life and amortization; discount rate = 10%; interest rate = 10%; fuel cost inflation rate = 7%; other operating cost inflation rate = 5%.

NOTES:

Pipeline (1) From gathering station to onshore pump station, 78 miles 14-inch I.D., 1-inch wall; from pump station to shore, 32 miles, 12-inch I.D. 3/4-inch wall.

Pipeline (2) From gathering station to offshore pump station 70 miles 14-inch I.D., 1-inch wall; from offshore pump station to shore, 12-inch I.D., 1-inch wall.

Pipeline (3) From gathering station to shore (no pump station) 118 miles, 16-inch I.D., 1-inch wall.

1. SANTA ROSA-CORTES (NORTH)

As displayed in Tables III-1 and III-2, the costs per barrel for the low estimate of reserves favor the tanker system over pipelines by 6 cents per barrel. As shown in Figure II-2, pipeline route 1 provides for clearances at least 3 miles from the shore of Santa Cruz Island. This requires pipelining in depths approaching 2,000 feet; therefore, pipeline construction costs are considerably high. When the requirement to remain 3 miles offshore of Santa Cruz Island is removed, pipeline routes 2, 3, and 4 (shown in Figure II-3) will significantly reduce the pipeline alternative costs. By laying the pipeline across Santa Cruz Island or through the Santa Cruz Channel, though the distance is not substantially different, the maximum depth of pipelay is reduced nearly 50 percent. The economics now shift in favor of pipeline route 2, that is, directly across the island to Ventura, by a reduction of 9 cents per barrel when compared to the tanker system.

The larger estimates of reserve slightly favor the deep water pipeline route 1 over the tanker system. When the requirement to remain 3 miles offshore is removed, cross-island route 2 is the most economical alternative at a cost of 8 cents per barrel for pipeline, as compared to 19 cents per barrel for the tanker system. Pipeline routes 4 and 3 are the next most economical pipeline routes, respectively.

2. SANTA BARBARA-SANTA CATALINA

For this proposed lease area, Table III-3 shows an unexpectedly high cost (60 cents) per barrel for the tanker system. The high cost is caused primarily by the use of a 16,000-ton tanker when a 10,000-ton tanker would have been adequate. A 10,000-ton tanker is the smallest available from the existing U.S. flag tanker fleet. In view of this and the relatively short transport distance of 20 miles, a tug barge system was considered as a transport system alternative. The transport costs for tug barge as shown in Table III-4 were substantially lower than those for the tanker system (36 cents per barrel); however, the pipeline is still the less expensive alternative. For the larger estimate of reserves, pipeline is the more economical alternative at 11 cents per barrel as compared to 21 cents per barrel for the tanker. Although transiting depths as great as 3,000 feet, the 20-mile transport distance is the key factor in determining that a pipeline is the optimal economic alternative.

3. SANTA ROSA-CORTES (SOUTH)

Table III-5 shows the costs of a pipeline for the low estimate of reserves to be minimum when the onshore pump station and smaller diameter pipe are used. When the offshore pump station or the larger diameter pipe are used, the costs are higher by 22 cents and 19 cents

per barrel, respectively. However, due to the length of the pipelines (over 100 miles for all 3 pipeline alternatives) the tanker system costs are the lowest. The tanker system costs are 28 cents per barrel less than the least expensive pipeline route.

For the high estimates of reserves, the smaller diameter pipeline with the onshore pump station is again the least expensive pipeline system. The length of the required pipeline, however, makes even this least expensive pipeline route more costly than the tanker system. As shown in Table III-6 for the higher estimates of reserves, tanker costs are 11 cents per barrel cheaper than the least expensive pipeline route.

The analysis of the hypothetical transport systems leads to the following conclusions regarding trends in OCS transportation economics:

- Surface marine transport systems are favored over pipelines in cases where the following exist:
  - Recoverable reserves are small
  - Transport distances are great
  - Pipeline routes are in deep water
- Submarine pipelines are favored over tanker systems in cases where the following exist:

- Reserves are large
- Transport distances are short
- Depths along pipeline routes are limited.

When evaluating the economics of OCS transport systems, each proposed lease site must be examined on the basis of the above conclusions in order to determine the economically optimal transport alternative.

IV. ESTIMATION OF OIL SPILL RISK

1. INTRODUCTION

The approach adopted for determining the transportation oil spill risks for three hypothetical production sites offshore southern California combines analysis of available oil spill statistics in a Bayesian framework with analytically-derived worst case oil spill estimates based on transport mode design criteria. It is an application and extension of the work of Devanney and Stewart.* Calculations are made for the expected number of spills, the expected spill magnitude, and the expected total volume spilled for both small spills (less than 1,000 barrels and large spills (greater than 1,000 barrels).

The expected number of tanker and pipeline spills over the life of each oil field is calculated based on the combination of:

- A probability distribution characterizing prior judgment as to the nature of the spill generating process

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* J. W. Devanney III and R. J. Stewart, assisted by Virgil Keith and Joseph Porricelli, "Analysis of Oil Spill Statistics," Report to Council on Environmental Quality, April 1974.

- A probability distribution whose parameters are determined by the available data.

The expected tanker and pipeline spill magnitude is also calculated based on the combination of a prior distribution and a distribution parameterized by the available data. Based upon specific tanker and pipeline systems designed for the three hypothetical developments (described in Chapter II), worst case estimates of oil spills are developed. These estimates become the upper bounds of the data samples from which expected spill magnitudes are calculated. Finally, an estimate of the expected total amount of oil spilled over the life of each field is developed as the product of the expected number of spills and the expected spill magnitude.

2. METHODOLOGY

This section details the methodology employed in estimating oil spill risk for each hypothetical oil field. The approach adopted derives not only the total volume of oil expected to be spilled over the life of each field but the expected number of minor and major spills as well as their respective expected magnitude. A thousand barrels is chosen arbitrarily as the dividing line between minor and major spills. This section describes the derivation of the equations used in the analysis in three parts:

- Spill frequency
- Spill magnitude
- Total volume spilled.

The next section specifies the sources of data for this study.

(1) Spill Frequency

Following the methodology of Devanney and Stewart, it is assumed that spill occurrence is determined by a Poisson process. This means that the probability of a spill during a particular interval is proportional to the amount of exposure in this interval and spills are generated independently, that is, the probability of a spill is not affected by the history of past spills. The Poisson distribution has two parameters, the contemplated exposure and the intensity. The intensity of the Poisson process is the mean spill rate. This is an uncertain quantity lying somewhere between 0 and ∞; but prior to examining the spill data, no further judgment can be made. A Gamma distribution with parameters equal to zero suitably characterizes the nature of the intensity variable before observing the data. The parameters of the Gamma distribution are then determined by the data on numbers of spills observed and observed exposure.

The exposure variable is taken to be volume of oil handled, although other measures such as number of landings, number of pipeline miles, or number of tanker trips are also possibilities. For comparative purposes, two measures of the expected number of spills for tanker spills less than 1,000 barrels were calculated, one based on the number of tanker trips, and the other based on the volume of oil handled as described in Section 3 of this chapter.

Given a contemplated exposure of t units (for example, volume of oil to be handled, number of trips), the distribution of the number of future spills, n, can be determined. For each n, it is the probability of n spills given each possible value of intensity (the Poisson distribution) times that value of intensity (the Gamma distribution) summed over all possible intensity values. After some computation, this turns out to be a negative binomial distribution:

$$\rho\,(n/t, v, \tau) = \frac{(n + \nu - 1)\,!\; t^{n}\, \tau^{\nu}}{n\,!\,(\nu - 1)\,!\,(t + \tau)^{n+\nu}}$$

where v = number of spills observed
τ = observed exposure (volume of oil handled, number of trips, etc.)
t = contemplated exposure
n = number of spills over field life.

For large samples, the mean of the above distribution, the expected number of spills over the life of the field, is equal to $\bar{n} = v \frac{t}{\tau}$. This equation is used to compute the expected number of spills for both the small and large spill magnitude categories.

(2) Spill Magnitude

Since spills due to different causes are likely to have different most likely values, the distribution of the spill magnitude is likely to be multimodal. Spills greater and less than 1,000 barrels are analyzed separately in recognition of the multimodal nature of the spill magnitude distribution. Within each of the two spill magnitude categories, a single-peaked distribution is assumed for simplicity. The Gamma distribution has two parameters which can be varied to obtain an approximation to any single-peaked distribution over the interval 0 to ∞. The division of the analysis of spill magnitude into two parts is a good approach because oil spill statistics generally indicate the occurrence of a relatively small number of major spills interspersed with a relatively large number of minor spills.

Since the actual values of the parameters of the Gamma distribution are unknown, they, in turn, are assigned a

probability distribution. Devanney and Stewart use a Gamma-hyperpoisson because it is determined by the spill size data sample alone and can be combined with the Gamma distribution without too much analytical complexity. Given the data, the combination distribution of spill magnitude, x, is the product of these Gamma and Gamma-hyperpoisson distributions summed over all possible values of the parameters of the Gamma distribution:

$$f(x/m, s, p) = \int_0^\infty \frac{(x\rho)^{\rho-1} \Gamma[(m+1)\cdot\rho]\, d\rho}{\Gamma(\rho)^{m+1}\, S(m, s, p)\, (x+s)^{(m+1)\cdot\rho}}$$

where m = number of spills observed

$s = \Sigma x_i$ total amount spilled

$p = \Pi x_i$ = product of all the individual spill sizes

ρ is a dummy variable

$S(m, s, p)$ is a normalizing constant.

The mean of this distribution approaches the sample mean s/m for large m:

$$\bar{x} = s/m \left[\frac{1}{1 - 1/m}\right].$$

The equation, $\bar{x} = s/m$, is used to calculate the expected spill magnitude for both the small and large spill magnitude categories.

An upper bound spill magnitude is established based on analytically-derived worst case spills for tankers and pipelines. Two estimates of tanker worst case spills are used in the analysis:

- Full tanker capacity
- 65 percent of tanker capacity.

There is a small chance that the full tanker capacity will be lost in a particular tanker accident. According to worldwide data on large tanker spills between 1967 and 1972, there is a 90-percent chance that the maximum spill will be only 65 percent of tanker capacity. The pipeline worst case spill is estimated based on the assumption that block valves are installed at intervals of ten miles along the pipeline so that only the volume of oil contained in ten miles of pipeline can possibly be lost after system shutdown assuming total pipeline rupture. It is also assumed that, in addition, oil flows out of the pipeline in the worst case for one hour before the rupture is detected and the system is shut down. The worst case spill

estimates are used only to establish upper bounds for the data samples used to calculate expected spill magnitudes.

(3) Total Volume Spilled

The expected total volume spilled over the life of each field is estimated to be the product of the expected number of spills over the life of each field and the expected spill magnitude.

3. SOURCES OF DATA

Tables IV-2 and IV-3 presented on pages IV-15 and IV-16 detail the sources of the data used to estimate oil spill risks in transporting oil by tanker and pipeline from the proposed lease sites at Santa Rosa-Cortes North and South and Santa Barbara-Santa Catalina. A special printout was obtained from the U.S. Coast Guard tape on "Polluting Incidents In and Around U.S. Waters" showing all spills in the area of southern California between latitudes $32^{o}30'$ and $34^{o}30'$ N. and longitudes $117^{o}00'$ W. (between San Diego and Point Concepcion) for 1973 and 1974. The data show 123 tanker and barge spills, all less than 1000 barrels in magnitude with the majority less than 3 barrels. Only two offshore pipeline spills are reported in the data for the same two years. These data are therefore used to calculate the frequency and magnitude of tanker spills

less than 1,000 barrels. The observed exposure is calculated on the basis of all crude and product transported by tanker and barge in 1973 and 1974 through all ports along the coast between San Diego and Point Concepcion. Contemplated exposure is the estimated volume of reserves in each field. It is assumed that the life of each field is 20 years, but this time period does not enter the analysis.

An alternative calculation of the expected number of tanker spills less than 1,000 barrels is based on the product of:

- The ratio of observed number of tanker and barge spills in southern California in 1973 and 1974 to observed tanker and barge round trips through the ports of the region
- The number of vessel round trips required to exploit the estimated reserves of each field.

Tankers are sized for each field for the low and high estimate of reserves according to the methodology described in Appendix A. The number of trips is simply the ratio of estimated reserves to tanker capacity.

The first measure of expected number of small tanker spills is proportional to the volume of oil handled, the second is proportional

to number of vessel trips. Certain accidents that result in spills are more closely related to the volume of oil handled, such as loading and unloading accidents. Furthermore, there is evidence that due to reduced maneuverability, large tankers have higher collision and grounding rates than small tankers.* On the other hand, many accidents that result in spills are more closely related to vessel movements than to volume handled. If the relationship between tanker size and collision rate is a weak one, for example, then more spills should be associated with a system involving a large number of small tanker movements than with a system involving a small number of large tanker movements.

In the calculations shown in Table IV-2, the first measure of the expected number of small tanker spills yields a considerably higher result for the high estimate of the reserves of each field than for the low estimates. The second measure yields approximately the same result for the two estimates of reserves because the number of tanker trips stays nearly constant as tanker size increases with estimated reserves. In deriving the estimate of the expected total

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* Based on interviews on the subject of world tanker spill data with representatives of ECO, Inc.

amount of oil spilled by tankers in amounts less than 1,000 barrels, the average of the two measures of expected number of spills is used. Estimates of the number of tanker spills less than 1,000 barrels presented in Table IV-2 are understated because the Coast Guard file of oil spills for 1974 is incomplete due to delays in reporting and coding. This makes little difference in the total expected oil spilled since spills less than 1,000 barrels account for 3 percent or less of total volume.

The number and magnitude of tanker spills greater than 1,000 barrels are calculated on the basis of data reported by ECO, Inc. on worldwide tanker spills between 1967 and 1972. The observed exposure is taken to be the volume of oil landed from trade routes on which the reported spills occurred following Devanney and Stewart in "Analysis of Oil Spill Statistics." A reliable measure of vessel movements applicable to the data base on worldwide large tanker spills was not found; therefore, the alternative calculation of spill frequency is omitted in this case.

Pipeline spill frequency and magnitude are calculated on the basis of offshore pipeline spills greater than 1,000 barrels between 1964 and 1972 reported by Devanney and Stewart. Coast Guard data for the United States as a whole include offshore pipeline spills less

than 1,000 barrels but do not differentiate clearly among those that emanated from platforms, gathering lines, or transmission lines. This distinction is crucial in comparing pipelines and tankers since the platform and gathering lines are part of the delivery system in either case. There are indications that a very large proportion of these spills are associated with platforms. Furthermore, the average magnitude of these spills is less than four barrels. The omission of pipeline spills less than 1,000 barrels from the analysis due to shortcomings in the data is not serious since they account for a very small percentage of the expected total volume spilled. Onshore liquid pipeline spill data from the Department of Transportation, Office of Pipeline Safety, were also examined but not used because the distinction between very small and very large spills could not be made.

The exposure variable for the pipeline spill frequency calculations is the volume of oil produced offshore and landed by pipeline. Another measure of exposure, such as pipeline miles, could be used. In this case, the same number of spills is expected using two pipelines of the same length but different diameter. In fact, there is evidence that spill frequency increases with pipeline size. A better measure than volume handled, however, may be inch-miles of

pipeline (the product of diameter and length) since this is proportional to the area of pipeline surface exposed to accidents. In the time available for this study, it was not possible to acquire appropriate data on exposure in terms of inch-miles, although this might prove to be a worthwhile refinement of the results of this study in the future. In this case, the expected number of spills would not increase by as large a factor in moving from the low to the high estimate of reserves.

4. RESULTS OF THE ANALYSIS

This section presents the results of the analysis of oil spill risk. The estimates of expected spill frequency, spill magnitude and total volume spilled are shown in tabular form. Causes of oil spills identified in the data are also examined in this section. Since pipeline spill data used in the analysis is based largely on experience in the Gulf of Mexico, an analysis of the probability of earthquake-caused pipeline spills offshore southern California is carried out.

(1) Spill Estimates

The results of the analysis of oil spill risk are summarized in Table IV-1. Intermediate calculations for tankers are shown in Table IV-2, under the assumption that the worst case tanker spill is 100 percent of tanker capacity. Intermediate calculations for pipelines are shown in Table IV-3, under the

Table IV-1
Oil Spill Risk Summary

Production Field	Expected Total Amount Spilled by Tanker, Field Life (barrels)		Expected Total Amount Spilled by Pipeline, Field Life (barrels)	
	Worst Case Assumption		Worst Case Assumption	
	100% Capacity Outflow	65% Capacity Outflow	10-mile Drain	5-mile Drain
Santa Rosa-Cortes (N)				
Low Estimate of Reserves	21,200	12,200	3,200	2,600
High Estimate of Reserves	48,300	40,300	6,800	5,400
Average*	34,750	26,250	5,000	4,000
Santa Barbara-Santa Catalina				
Low Estimate of Reserves	3,100	2,850	600	300
High Estimate of Reserves	13,200	9,200	2,600	2,200
Average*	8,150	6,025	1,600	1,250
Santa Rosa-Cortes (S)				
Low Estimate of Reserves	20,200	15,200	3,200	2,500
High Estimate of Reserves	89,400	84,400	13,400	10,400
Average*	54,800	49,800	8,300	6,450

*Average of the expected total amount spilled results based on the low and the high estimates of reserves.

	t_1 Contemplated Exposure = USGS Estimated Reserves (Barrels)	t_2 No. of Trips Field Life (1)	$\hat{n}_1$ Expected No. of Tanker Spills Greater than 1,000 barrels, Field Life (2)	$\bar{z}_1$ Expected Tanker Spill Magnitude, Spills Greater than 1,000 barrels (3) (barrels)	$\hat{z}_1$ Expected Total Amount Spilled by Tanker in Spills Greater than 1,000 barrels, (4) Field Life (barrels)	$\hat{z}_1/\hat{z}$ Percentage of Expected Total Amount Spilled by Tanker Field Life
Santa Rosa-Cortes (N)						
Low Estimate of Reserves	242×10^6	1732	.82	25,000	21,000	99%
High Estimate of Reserves	431×10^6	1745	1.46	33,000	48,000	99%
Santa Barbara-Santa Catalina						
Low Estimate of Reserves	67×10^6	644	.23	15,000	3,000	97%
High Estimate of Reserves	219×10^6	1982	.74	18,000	13,000	98%
Santa Rosa-Cortes (S)						
Low Estimate of Reserves	239×10^6	1414	.81	25,000	20,000	99%
High Estimate of Reserves	660×10^6	1430	2.23	40,000	89,000	99.6%

(1) Ratio of Estimated Reserves, t_1, to tanker capacity

(2) $\hat{n}_1 = v_1 \frac{t_1}{\tau_1}$, where $v_1 = 99$ (observed no. of spills greater than 1,000 barrels, worldwide, 1967-1972, ECO, Inc.) and $\tau_1 = 29.3 \times 10^9$ barrels (observed exposure = volume of oil landed from trade routes on which these spills occurred, "Analysis of Oil Spill Statistics," J.M. Devanney III and R.J. Stewart, MIT.)

(3) Based on the average magnitude of spills from the ECO, Inc. tape (worldwide, 1967-1972, greater than 1,000 barrels) that are smaller than the tanker capacity (worst case spill) in each case

(4) $\hat{z}_1 = \hat{n}_1 \cdot \bar{z}_1$

(5) $\hat{n}_2 = v_2 \frac{t_1}{\tau_2}$, where $v_2 = 123$ (1973-1974, U.S. Coast G through Southern Califor

(6) $\hat{n}_2 = v_2 \frac{t_2}{\tau_3}$, where $\tau_3 = 9213$ (U.S. Army Corps of Engi

(7) Average spill magnitude,

(8) $\hat{z}_2 = \hat{n}_2 \cdot \bar{z}_2$

(9) $\hat{z} = \hat{z}_1 + \hat{z}_2$

Table IV-2
Tanker Oil Spill Risk

(3)	$\bar{z}_1$ Expected Total Amount Spilled by Tanker in Spills Greater than 1,000 barrels, Field Life (barrels) (4)	$\bar{z}_1/\bar{z}$ Percentage of Expected Total Amount Spilled by Tanker Field Life	$\bar{n}_2$ Expected No. of Spills Less than 1,000 barrels, Field Life Based on t_1 (5)	Based on t_2 (6)	$\bar{x}_2$ Expected Tanker Spill Magnitude Spills Less than 1,000 barrels (barrels) (7)	$\bar{z}_2$ Expected Total Amount Spilled by Tanker in Spills Less than 1,000 barrels, Field Life (barrels) (8)	$\bar{z}_2/\bar{z}$ Percentage of Expected Total Amount Spilled by Tanker Field Life	$\bar{z}$ Expected Total Amount Spilled by Tanker Field Life (9)
	21,000	99%	46.2	23.1	5.22	200	1%	21,200
	48,000	99%	82.6	23.3	5.22	300	1%	48,300
	3,000	97%	13.1	8.6	5.22	100	3%	3,100
	13,000	98%	42.0	26.5	5.22	200	2%	13,200
	20,000	99%	45.7	18.8	5.22	200	1%	20,200
	89,000	99.6%	126.2	19.1	5.22	400	0.4%	89,400

(5) $\bar{n}_2 = v_2 \frac{t_1}{\tau_2}$, where v_2=123 (observed no. of tanker and barge spills less than 1,000 barrels, Southern California, 1973-1974, U.S. Coast Guard) and τ_2=6.43x10^8 barrels (crude and product transported by tanker and barge through Southern California ports, 1973-1974, U.S. Army Corps of Engineers.)

(6) $\bar{n}_2 = v_2 \frac{t_2}{\tau_3}$, where τ_3=9213 (no. of tanker and barge round-trips through Southern California ports, 1973-1974, U.S. Army Corps of Engineers.)

(7) Average spill magnitude, spills less than 1,000 barrels, Southern California, 1973, 1974, U.S. Coast Guard.

(8) $\bar{z}_2 = \bar{n}_2 \bar{x}_2$

(9) $\bar{z} = \bar{z}_1 + \bar{z}_2$

6

Table IV-3
Pipeline Oil Spill Risk

	$\bar{n}_p$ Expected No. Offshore Pipeline Spills, Spills Greater than 1,000 barrels, Field Life (1)	$\bar{x}_p$ Expected Pipeline Spill Magnitude Spills Greater than 1,000 barrels(2) (barrels)	$\bar{z}_p$ Expected Total Amount Spilled by Pipeline, Spills Greater than 1,000 barrels(3) (barrels)
Santa Rosa-Cortes (N) (53 mile route around Channel Islands)			
Low Estimate of Reserves	.63	5,100	3,200
High Estimate of Reserves	1.11	6,100	6,800
Santa Barbara-Santa Catalina (20-mile route)			
Low Estimate of Reserves	.17	3,300	600
High Estimate of Reserves	.57	4,600	2,600
Santa Rosa-Cortes (S) (110-mile route with pump station on Santa Cruz Island)			
Low Estimate of Reserves	.62	5,100	3,200
High Estimate of Reserves	1.70	7,900	13,400

(1) $\bar{n}_p = v_p \frac{t_1}{\tau_p}$, where v_p =8 (observed no. of offshore pipeline spills greater than 1,000 barrels, worldwide, 1964-1972, from "Analysis of Oil Spill Statistics," Devanney & Stewart) and $\tau_p = 3.17 \times 10^9$ barrels (observed exposure = volume of crude oil landed from offshore pipelines, 1964-1972, Devanney & Stewart).

(2) Based on average magnitude of the offshore pipeline spills less than the worst case pipeline spill predicted analytically for each case.

		Low Est. of Reserves	High Est. of Reserves
Worst Case Spills: (barrels)	Santa Rosa-Cortes (N)	14,000	20,000
	Santa Barbara-Santa Catalina	4,500	11,000
	Santa Rosa-Cortes (S)	14,000	31,000

(Worst case based on total pipeline rupture, 1 hour undetected outflow and loss of all the oil in the pipeline between check valves (valve spacing: 10 miles) after system shutdown)

(3) $\bar{z}_p = \bar{n}_p \cdot \bar{x}_p$

assumption that the worst case spill is the volume of oil contained in ten miles of pipeline plus the volume of oil spilled in one hour of undetected outflow. Summary Table IV-1 compares the expected total spill volume results derived under the above assumptions to expected total spill volumes calculated on the basis of less conservative alternative assumptions as to the worst case spill. These alternative assumptions are that

- The worst case tanker spill is 65 percent of tanker capacity (based on 90 percent of the data sample) and
- The worst case pipeline spill is the volume of oil contained in five miles of pipeline (block value every five miles) plus the amount of oil spilled in one hour of undetected outflow.

Comparison of the relatively high estimates of expected total amount spilled, columns 1 and 3 in Table IV-1, shows that:

- Pipelines are safer by a factor of 7 in the case of Santa Rosa-Cortes (N)

- Pipelines are safer by a factor of 5 in the case of Santa Barbara-Santa Catalina

- Pipelines are safer by a factor of 6.5 in the case of Santa Rosa-Cortes (S).

Comparison of the high-side tanker estimates with the low-side pipeline estimates, columns 1 and 4 of Table IV-3, shows pipelines to be safer than tankers by a factor of 9 in the case of Santa Rosa-Cortes North and South, and a factor of 7 in the case of Santa Barbara-Santa Catalina.

Although the results of this assessment of oil transportation risk show pipeline to be safer than tanker for all three hypothetical fields, the estimates of expected total volume spilled for tanker and pipeline are within the same order of magnitude even when comparing the upper end of the range of the tanker spill estimates to the lower end of the range of pipeline spill estimates. Therefore, one should be cautious in recommending pipelines on the basis of risk. Future analysis could certainly refine the results. Data on offshore pipeline spills are, at present, especially inadequate and as mentioned earlier, alternate measures of exposure should be tested.

(2) Spill Causes

Because of the nature of available data, the approach to the problem of oil transportation risk analysis requires that statistics covering a variety of geographical areas be employed in order to achieve adequate sample sizes. For example, expected tanker spill frequency and magnitude is based on southern California spill data for spills less than 1,000 barrels and on worldwide data for spills greater than 1,000 barrels It was decided earlier in the study that an approach such as a fault-tree analysis, in which modal spill probabilities would be computed based on probabilities of site-specific spill causes and accident sequences, was impractical at present because of the lack of data and the compounded uncertainties of an interrelated chain of events. Because of the use, to a large extent, of general rather than site-specific data in the approach, it is likely that certain causes of oil spills are given too much weight in the context of likely physical conditions and transport systems offshore southern California while other causes of oil spills are either given too little weight or not taken into account at all.

The data sample on tanker spills greater than 1,000 barrels does not include spill causes. The Coast Guard printout

on small tanker and barge spills in southern California does list immediate and contributory spill causes, however. Table IV-4 breaks down these spills by immediate cause.

Table IV-4
Tanker and Barge Spill Immediate Causes
Southern California, 1973-1974

	% of Total
Structural failure	12
Equipment failure	29
Personnel error	50
Intentional discharges, natural or chronic phenomena, unknown	9

Source: U.S. Coast Guard "Polluting Incidents In and Around U.S. Waters," 1973 and 1974.

Most of the structural failure spills involve hull ruptures or leaks. Over half of the equipment failure spills are due to valve failures. Other equipment failure spills involve hose ruptures or leaks, gasket failures, and pump failures. Almost 40 percent of the spills caused by personnel error are the result of tank overflows. The remainder are the results of improper equipment handling and other personnel errors.

Accidents that cause some of the structural failure spills include groundings, collisions, explosions, and material failures. Table IV-5 is a breakdown of tanker and barge accidents reported in southern California from 1969 through 1974.

Table IV-5
Reported Tanker and Barge Accidents
Southern California, 1969-1974

	% of Total
Groundings	11
Collisions	38
Explosions	8
Material failures	38
Flooding, swamping	3
Fouled propeller	3

Source: U.S. Coast Guard, "Commercial Vessel Casualties," 1969-1974.

Although the data presented in Table IV-4 represent only the causes of tanker and barge spills less than 1,000 barrels reported in southern California in 1973 and 1974, there is reason to believe that the same causes may be responsible for larger oil spills.

The data base for offshore pipeline spills greater than 1,000 barrels (covering spills mostly in the Gulf of Mexico) is very small but includes two spills caused by anchor-dragging,

one spill caused by a tug collision close to shore, one spill caused by equipment failure, and several spills caused by breaks and leaks of unknown cause. With adequate pipeline burial in shallow waters, the probability of spills caused by anchor-dragging or collision will be clearly reduced. Onshore petroleum pipeline data show that external corrosion and line ruptures caused by excavation equipment are by far the major causes of onshore spills. However, corrosion spills occur most frequently in older pipelines that are inadequately protected. It is expected that corrosion will not be a significant problem for new offshore pipelines.

(3) Other Potential Pipeline Spill Causes

Other potential causes of offshore pipeline spills in southern California not accounted for in the data sample used to compute spill frequency include:

- Ocean storms and currents
- Loss of support due to slumping of unconsolidated sediments
- Seismic shaking

. Ground displacement due to surface faulting

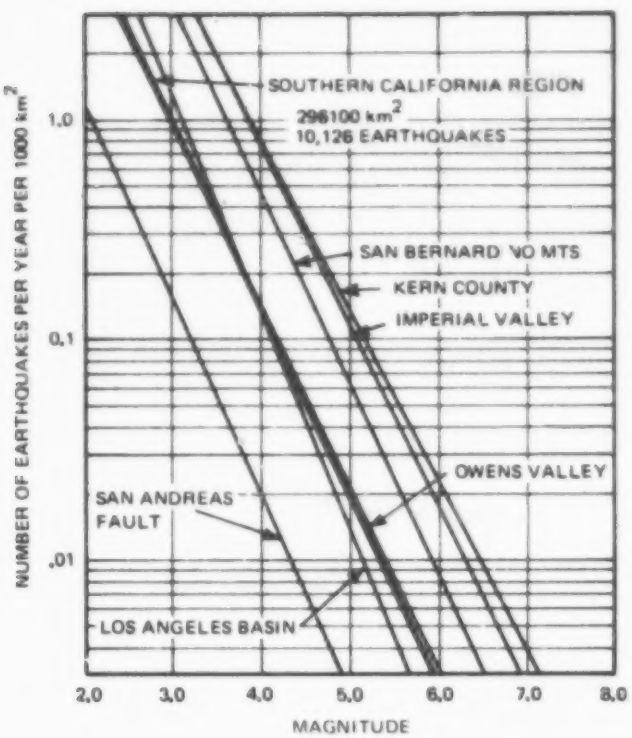
. Breakage due to tsunami.

Because the earthquake risk to offshore pipelines is a problem specific to California, it is particularly relevant to attempt to put this factor into perspective.

Figure IV-1 indicates the recurrence interval estimated for earthquakes of different magnitudes on the Richter scale based on the earthquake history in southern California from 1934 through 1963. Curves for the southern California region as a whole and for several subregions are compared.

Integration of the recurrence curve for southern California as a whole yields an estimate of 1.3×10^{-3} earthquakes greater than or equal to 6.0 on the Richter scale per year per thousand square kilometers, or 7.8 earthquakes over the 20-year life of an offshore oil field. As a rough estimate, if one out of ten earthquakes is felt in the area traversed by a particular proposed pipeline route and, of those felt, one out of ten causes a pipeline to rupture, then the number of earthquake-caused spills over the life of a particular field is .078. This is less than 10 percent of the expected number of offshore

FIGURE IV-1
Comparison of Recurrence Curves for
Earthquakes in Southern California



Source: C. R. Allen, P. St. Amand, C. F. Richter, and J. M. Nordquist, "Relationship Between Seismicity and Geologic Structure in the Southern California Region," Bulletin of the Seismological Society of America, Vol. 55, No. 4, p. 781, August, 1965.

pipeline spills shown in Table IV-3 for Santa Rosa-Cortes North, and less than 7 percent of the expected number of spills for Santa Rosa-Cortes South.

The Santa Barbara-Santa Catalina field is within the area defined as the Los Angeles Basin in the available earthquake recurrence data. Here, the data predict that 0.14 earthquakes greater than or equal to 6.0 will occur over the life of the field. If all of these are felt along the pipeline route and one out of ten causes a rupture, then the number of earthquake-caused spills over the life of the field is .014, less than 5 percent of the frequency estimate presented in Table IV-3.

Table IV-6 indicates expected earthquake-caused spills as a percentage of the expected number of offshore pipeline spills (average of the low and the high estimates in Table IV-3). This percentage is calculated under alternative assumptions as to the percentage of expected earthquakes felt in the area traversed by the pipeline and the percentage of those earthquakes felt in the area which cause a pipeline rupture. Only the results based, in our judgment, on overly pessimistic assumptions show the expected earthquake-caused spills to be a significant percentage of total expected number of pipeline spills.

Table IV-6
Earthquake-Caused Pipeline Spills as Percentage of Expected Number of Pipeline Spills From Table IV-3

Santa Rosa-Cortes North

% of those felt which cause a pipeline rupture	% felt in area traversed by pipeline			
	20	10	5	2
20	36.0%	18.0%	9.0%	3.6%
10	18.0%	9.0%	4.5%	1.8%
5	9.0%	4.5%	2.3%	0.9%
2	3.6%	1.8%	0.9%	0.4%

Santa Rosa-Cortes South

% of those felt which cause a pipeline rupture	% felt in area traversed by pipeline			
	20	10	5	2
20	26.8%	13.4%	6.7%	2.6%
10	13.4%	6.7%	3.4%	1.3%
5	6.7%	3.4%	1.7%	0.7%
2	2.6%	1.3%	0.7%	0.3%

Santa Barbara-Santa Catalina

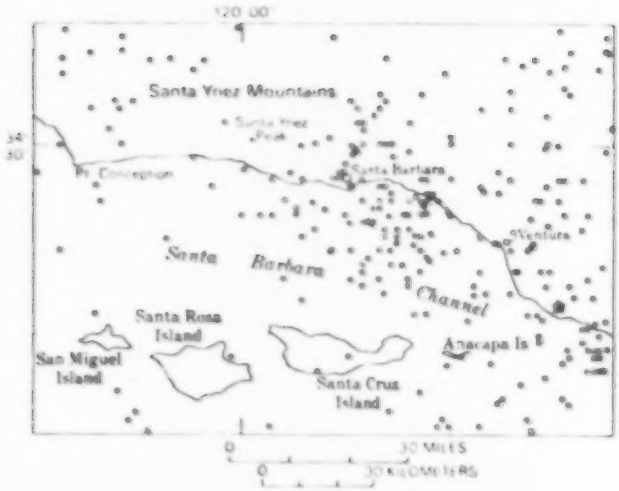
% of those felt which cause a pipeline rupture	% felt in area traversed by pipeline		
	100	50	20
20	7.6%	3.8%	1.5%
10	3.8%	1.9%	0.8%
5	1.9%	1.0%	0.4%
2	0.8%	0.4%	0.2%

Under the assumption that pipelines will be designed so that only a very large earthquake, such as 8.0 on the Richter scale, could cause a rupture, the expected number of earthquake-caused spills, once again, does not contribute significantly to overall pipeline spill frequency. The data predict that an 8.0 earthquake will occur once every 52 years in southern California. Assuming all such quakes are felt along the route of a particular proposed pipeline and that one out of ten results in a pipeline rupture, then the number of earthquake spills over the life of a field is only .031.

According to the assumptions used in the above analysis, earthquake risk is not a great enough factor to alter significantly the expected volume of oil spilled by an offshore pipeline over the life of the oil field. The estimates presented above mean that one earthquake-caused oil spill is expected every 256 years for the Santa Rosa-Cortes North and South fields and one earthquake-caused spill every 1,429 years for the Santa Barbara-Santa Catalina field.

Figure IV-2 shows that the epicenters of earthquakes in the Santa Barbara Channel region from 1934 to 1967 are concentrated between Santa Cruz Island and the City of

FIGURE IV-2
Epicenters of Earthquakes
In the Santa Barbara Channel Region
From 1934-1967



NOTES:

- Magnitude less than 4
- Magnitude greater than or equal to 4
- Point Mugu, 1973

Source: R. M. Hamilton, et al., "Seismicity and Associated Effects Santa Barbara Region": U.S. Geol. Survey Prof. Paper 679-I.

Santa Barbara, in an area to the east of the hypothetical pipeline routes from Santa Rosa-Cortes North and South. As a worst case estimate of the earthquake spill frequency, it is assumed that, of the 7.8 earthquakes of magnitude 6.0 or greater predicted throughout southern California over the 20-year life of an offshore oil field, one out of five is felt in the area of greatest past earthquake epicenter concentration, and, of those felt, one out of ten causes a pipeline rupture. If the pipeline passes through this area, the expected number of earthquake-caused spills over the life of the field is .156, or one spill every 128 years. This is about 20 percent of the expected number of offshore pipeline spills over the life of Santa Rosa-Cortes North and about 13 percent of the expected number of pipeline spills over the life of Santa Rosa-Cortes South. Therefore, the risk of an earthquake-caused oil spill in one of the most earthquake prone areas offshore southern California does not significantly alter the risk of pipeline transport compared to tanker transport.

APPENDIX A

METHODOLOGY FOR ASSESSMENT OF TRANSPORTATION SYSTEMS COST

1. DETERMINING MAXIMUM BARRELS PER DAY OUTPUT FROM PROPOSED LEASE FIELDS

Referring to Figure A-1, the maximum output in barrels per day is determined by:

$$Q = \frac{\text{ESTIMATED RECOVERABLE RESERVES}}{10 \times 365}$$

Q = BARRELS/DAY

Example: USGS estimated recoverable reserves for Santa Rosa-Cortes (North) is from 242,000,000 to 431,000,000 barrels; using the low estimate

$$Q = \frac{242,000,000}{365 \times 10}$$

Q = 66,301 BARRELS/DAY

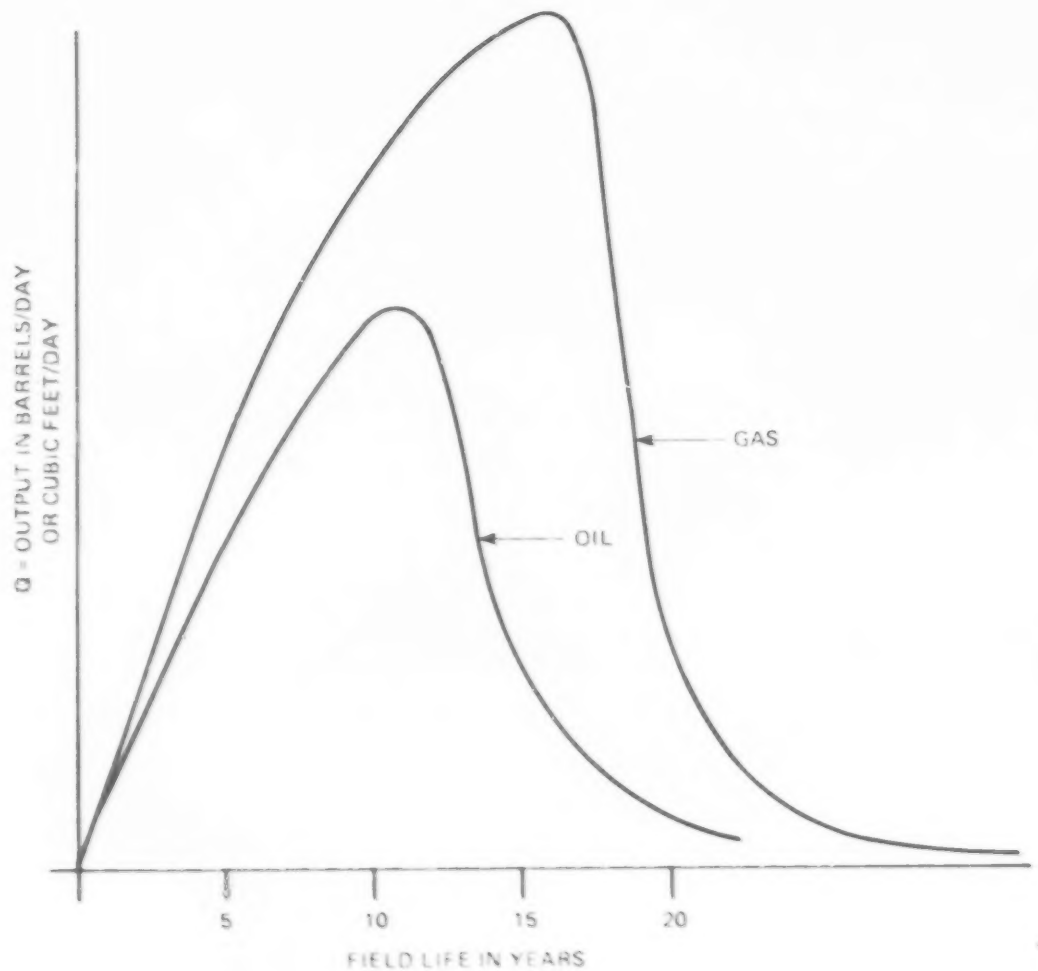
2. DETERMINING TIME REQUIRED FOR TANKER TO COMPLETE ONE OFFLOADING CYCLE

Given that crude oil carriers are designed for a 24 hour off-load period,* the time for one off-load cycle T can be determined by the formula

* Not applicable to VLCC and ULCC

APPENDIX A(2)

FIGURE A-1
Production Rate Versus
Field Life for Average Field



$$T = 24 + \frac{\text{DISTANCE (OFFSHORE TERMINAL TO ONSHORE TERMINAL)}}{\text{SPEED OF VESSEL}} \quad (2)$$

Example: Santa Rosa (North) field to Ventura equals 53.5 nautical miles by way of deep water route (see Figure II). Assuming speed of 15 knots:

$$T = 24 + \left(\frac{53.5}{15}\right)(2)$$

$$T = 31.7 \text{ HOURS}$$

To allow for docking delays and reduced speed when manuvering through the harbor channel T will be 36 hours for this example.

3. DETERMINING REQUIRED STORAGE FACILITIES

The amount of required storage will be a function of production rate and maximum anticipated time the tanker would be away from the production site. Therefore storage, S, will be

$$S = (\text{QBBLS/D})(\text{MAXIMUM TIME TANKER AWAY})$$

Where maximum time away will include time away due to adverse weather.

Example: For Santa Rosa-Cortes (North)

$$S = Q\,(3)$$

$$S = 66,301\,(3)$$

$$S = 198,900 \text{ BARRELS}$$

Where storage is by barge. Barge size will be determined by:

$$\text{Barge size} = \frac{S}{6.5 \text{ BARRELS/TON}}$$

Example: For Santa Rosa-Cortes (North)

$$\text{Barge Size} = \frac{S}{6.5}$$

$$= \frac{198,900}{6.5}$$

Barge Size = 30,600 TONS

4. DETERMINING REQUIRED TANKER SIZE

The tanker must be sized for the maximum anticipated time between loadings. This will occur when tanker delay, due to weather or casualty, is maximized. When this situation occurs, the storage facility will be full to capacity. The tanker therefore must be sized to off-load whatever production will be stored while the tanker is making its off-load run plus the production from the wells while loading stored oil. In addition the tanker must take some additional stored oil if storage is to be bled down. For the purpose of this study we shall use a bleed off rate of 20 percent per trip. Therefore tanker capacity is:

$$(Q)(T) + (Q)(\text{TIME TO LOAD}^*) + (.2S)$$

* Assume loading rate of 35,000 BARRELS/HOUR

Example: For Santa Rosa-Cortes (North)

$$\text{Tanker Capacity} = (Q)(T) + Q(\text{TIME TO LOAD}) + (.2S)$$

$$= (66,301)(1.5) + \frac{(66,301)(.2)(198,000)}{(35,000)(24)} + (.2)(198,000)$$

$$= 99,452 + 3,140 + 39,780$$

$$= 142,372 \text{ BARRELS}$$

Therefore tanker size in dead weight tons is determined by:

$$\text{D. W. T.} = \frac{\text{CAPACITY IN BARRELS}}{\text{6.5 BARRELS/TON}}$$

$$= \frac{142,372}{6.5}$$

$$= 21,500 \text{ TONS}$$

5. DETERMINING TANKER SYSTEM COSTS

For the purpose of this study, it is assumed that construction of new tankers is not required. Existing tankers can be chartered for dedicated transit service. This seems a just and practical assumption in view of the present status of the U. S. merchant fleet.

The costs of tanker systems will consist of chartering and operating expenses. The major operating expense is fuel. Charter costs will vary with the demand and supply of tankers. Based on interviews with current

charterers of small and medium size tankers (16,000 to 90,000 D. W. T.), a charter rate of $7 dollars per dead weight ton per month is used to calculate charter costs.

Fuel costs will vary with the consumption rate for the size tanker selected. There are rates of consumption for both inport and at sea steaming. It is therefore necessary to determine the amount of time the vessel will be steaming in either of the two steaming modes.

Example: Using the Santa Rosa-Cortes (North) field to determine costs of chartering a tanker system to transport crude oil to existing facilities in Ventura, California Figure II-2 (presented in Chapter II) displays the location of the lease field and the proposed water route to Ventura harbor. Based on the USGS low estimate of reserves, the the following information is determined given that:

- Estimated reserves — 242 million barrels = 66,300 barrels/day
- Round trip distance—107 miles
- Off-load time—1 day
- Transit time— 0.5 days
- Storage for 3 days— 30,600-ton barge
- Pumping rate from storage—35,000 barrels/hour

The time the tanker will be at the loading site must now be determined. During normal operations, the storage barge will contain 1.5 days of production when the tanker returns. Therefore the amount to load will be:

(PRODUCTION RATE) x (T)

(66, 300 BARRELS/DAY) (1 + 0.5 LAYS)

99, 450 BARRELS

At a loading rate of 35, 000 barrels/hour

$$\text{Loading time of storage} = \frac{99,450}{35,000 \times 24}$$

$$= 0.12 \text{ DAYS}$$

Since the tanker is designed to carry more than 1.5 day storage, to account for anticipated worse conditions, it will not be full after loading 1.5 days of normal storage. The remaining tanker capacity can be determined by subtracting from tanker capacity 1.5 days of storage, plus the amount of oil produced while loading storage, assuming that the tanker was loading products while loading storage.

Production while loading storage = 66, 300 BARRELS/DAY x 0.12 DAYS

= 7, 956 BARRELS

Remaining capacity of tanker = Tanker Capacity - (Storage + Production)

Tanker capacity in barrels = DWT x 6.5 BARRELS/TON

= 21, 500 x 6.5

= 139, 750 BARRELS

Remaining tanker capacity = 139, 750 - (99, 500 + 7956)

= 32, 294 BARRELS

Time to load remaining capacity $= \frac{\text{REMAINING TANKER CAPACITY}}{\text{DAILY PRODUCTION RATE}}$

$= \frac{32,294 \text{ BARRELS}}{66,300 \text{ BARRELS/DAY}}$

= .49 DAYS

The total inport steaming time will be the time to off-load plus time to load storage plus time to load remaining tanker capacity.

Total inport steaming time = 1.00 day off-load
.12 days load storage
.49 days load remaining tanker capacity
1.61

Total at sea steaming time = transit time

= 0.5 DAYS

Given that the fuel consumption rate for a 21, 500 ton tanker is

Inport steaming — 76 BARRELS/DAY

At sea steaming — 336 BARRELS/DAY

Amount of fuel required for one-trip cycle:

= (76)(1.61) + (336)(15)

= 290 BARRELS/CYCLE

Costs of fuel per cycle at $10.77 per barrel

$$290 \times \frac{\$10.77}{\text{BARREL}}$$

$$= \$3127.00/\text{CYCLE}$$

The annual cost for fuel will equal cost per cycle times the number of cycles per year. The number of cycles per year can be determined by:

$$= \frac{365 \text{ DAYS PER YEAR}}{\text{NUMBER OF DAYS FER CYCLE}}$$

$$= \frac{365}{2.11}$$

$$= 173 \text{ CYCLES PER YEAR}$$

Cost of fuel per year will be the number of cycles per year times the fuel costs per cycle:

$$= 173 \frac{\text{CYCLES}}{\text{YEAR}} \times \frac{\$3127}{\text{CYCLE}}$$

$$= \$541,000$$

The total annual cost for the tanker is the annual charter costs plus fuel costs

Total Annual Costs = Charter Costs + Fuel Costs

$$= (21,500)(7)(12) + 541,000$$

$$= \$2,347,000$$

6. DETERMINING TANKER SYSTEM CAPITAL COSTS

Although it is assumed that tankers would be drawn from the existing merchant fleet, certain capital investments are required. Mooring facilities are necessary for both the storage barge and tanker. The single point mooring system such as the one used by Exxon at their offshore drilling site in Yanez, California will be used for the purpose of this study. The system consists of a barge and its anchoring devices and the associated piping for loading the barge or the tanker with oil produced from the wells. The costs for such a system will normally be independent of tanker or barge size since the anchoring system must be designed for a 100-year storm factor which exceeds requirements for even the very large crude carriers. The costs of an SPM system are generally governed by the depth of water where the facility is to be located. The costs of a SPM in depths not to exceed 100 fathoms are estimated at $8 million.

Example: Santa Rosa-Cortes (North) field requires mooring facilities for a tanker and one storage barge. Water depths in this field will vary from 40 to 400 fathoms. By locating the gathering point at a position in the field of approximately 55 fathoms in depth, costs for two SPM's are estimated at $16 million. The cost for converting the existing tankers for single point mooring is estimated at $750,000.

In view of the current shortage of crude carrying barges, it is assumed the storage barges will require a capital outlay for construction. Present costs for barges are approximately $200 per ton.

Therefore, total capital costs will be the sum of barge construction costs, SPM installation costs, and SPM conversion of tanker costs.

TOTAL CAPITAL COSTS = BARGE + SPM + TANKER CONVERSION

TOTAL CAPITAL COSTS = $(30,600 \text{ TONS})\frac{(200)}{\text{TON}} + (8,000,000)(2) + 750,000$

For Sanata Rosa (N)

$= \$22,870,000$

7. DETERMINING LIFE CYCLE COSTS FOR TANKER SYSTEM

Life cycle tanker system costs are based on a 20-year life. The costs are broken down by capital costs and operating costs which consist of charter costs, fuel, and other miscellaneous items. Fuel is assumed to escalate at an annual rate of 7 percent and other operating costs at a rate of 5 percent. Future costs are discounted at a rate of 10 percent per year. The cost of capital is also assumed to be 10 percent. Based on the above assumptions, we can derive the formula below:

$$\text{Life Cycle Costs} = I + \sum_{N=1}^{20} F\,(.97)^{N-1} + \sum_{N=1}^{20} O\,(.95)^{N-1}$$

I = Initial investment
F = Fuel costs/year
O = Operating costs/year
N = 20 year field life

Example: To determine life cycle costs for tanker system in Santa Rosa-Cortes (North) field.

Capital Costs	= $22,870,000
Annual Charter Costs	= $ 1,806,000
Annual Fuel Costs	= $ 541,000
Discount Rate	= 10%
Interest Rate	= 10%
Inflation Rate (Fuel)	= 7%
Inflation Rate (Charter)	= 5%
Life Cycle	= 20 years

$$\text{Life Cycle Costs} = I + \sum_{N=1}^{20} F\,(.97)^{N-1} + \sum_{N=1}^{20} O\,(.95)^{N-1}$$

$$= 22,870,000 + \sum_{N=1}^{20} (541,000)\,(.97)^{N-1} + \sum_{N=1} 1,806,000\,(.95)^{N-1}$$

$$= \$53,216,000$$

8. DETERMINING SIZE PIPELINE (DIAMETER)

The diameter of a pipeline is a function of desired throughput, distance or length of the pipeline, and pressure, or more specifically, pressure drop per mile of pipeline. The formula below approximates the relationship between pipe diameter and the above factors.

$$P = \frac{Q^{1.748} V^{.252} S}{156.4D^{4.748}}$$

P = Pressure Loss, psi/Mile

Q = Throughput, Barrels/Day

V = Kinematic Viscosity

S = Specific Gravity

D = Inside Diameter of Pipe

A graphic display of this formula is shown in Figures A-2 and A-3. The graphs are displayed in terms of barrels per hour, pressure loss per mile and pipe size in inches (I. D.). Therefore, with a few basic assumptions, pipe diameter can be determined.

Example: Santa Rosa-Cortes (North) low estimate of recoverable reserves.

Assumptions:

. There is full flow through the pipe

- There is no pressure loss due to configurations (elbows, curves, etc.) in the pipeline
- The pipeline discharge pressure from the gas oil seperator is 1000 psi
- The pipeline suction pressure at the receiving point is 20 psi
- The pipeline is designed for anticipated maximum throughput at the peak of the field life.

From section 1

$$Q = 66,300 \text{ BBLS/D}$$

$$\therefore Q = \frac{66,300}{24}$$

$$= 2763 \text{ BARRELS/HOUR}$$

From Figure A-1

$$\text{Length Pipeline} = 53.5 \text{ miles}$$

$$\therefore P = \frac{1000\text{-}20 \text{ psi}}{53.5 \text{ miles}}$$

$$= 18.3 \text{ psi/mile}$$

From Table A-1

$$D = 14 \text{ inches I.D.}$$

APPENDIX A(15)

FIGURE A-2
Flow Chart for Crude Oil in Pipelines

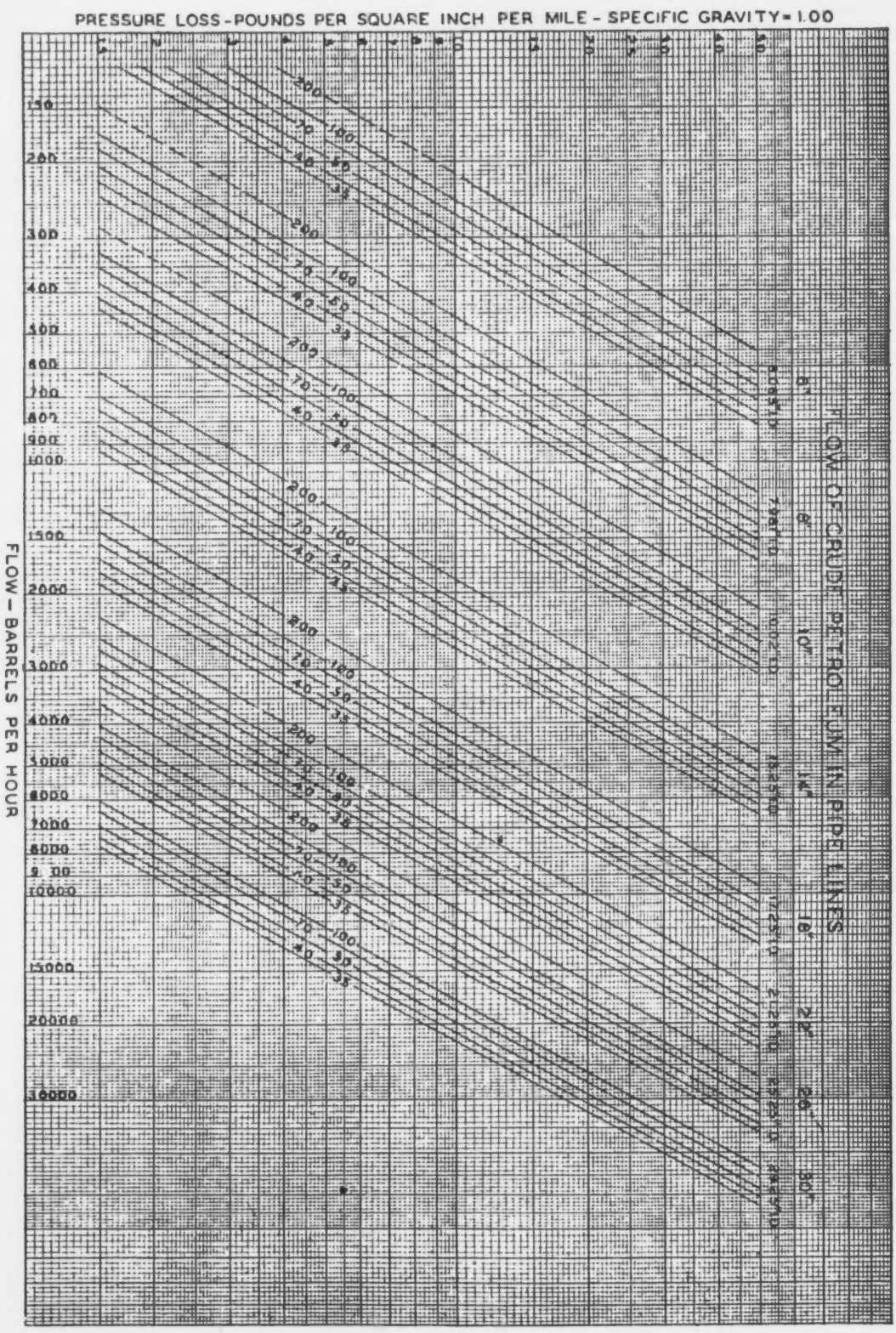
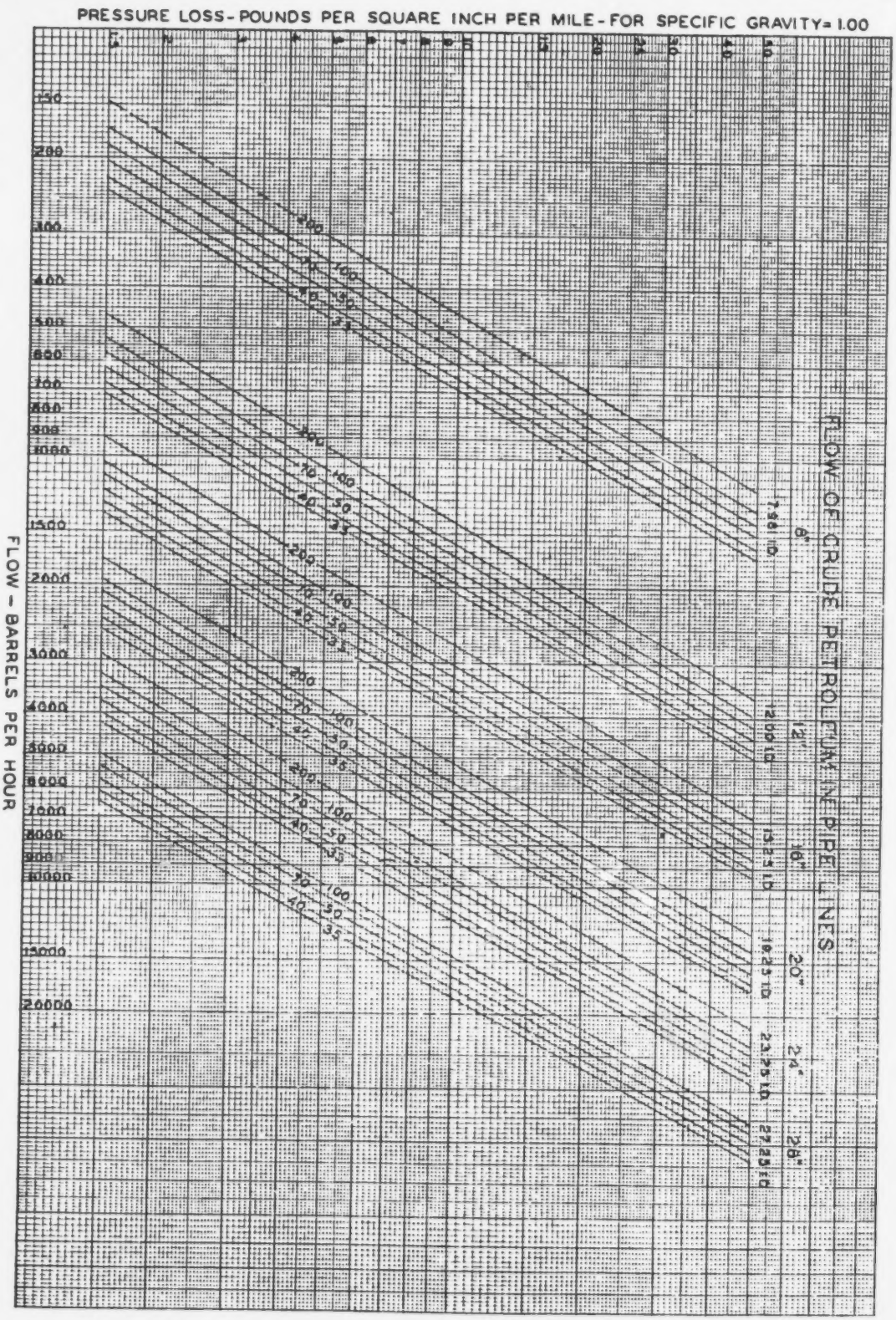


FIGURE A-3
Flow Chart for Crude Oil in Pipelines



9. DETERMINING PIPELINE CAPITAL COSTS

As mentioned previously, pipeline costs are a function of numerous factors. Depth and size, however, are the major inputs for casting offshore pipelines. Since pipelaying in depths which exist offshore southern California has yet to be accomplished, we have relied upon the estimates provided by those experts who were interviewed during the period of our study. It was the consensus that pipelaying costs in the waters off southern California could best be approximated as ten times the cost of equivalent size overland pipe.

Table A-1 lists the costs of overland pipe construction for various size pipe. Using this table and correcting for a 30 percent costs increase since 1969, pipeline costs have been calculated.

Example: Santa Rosa-Cortes (North)

Costs for a 14-inch I. D. pipeline over a distance of 53.5 miles

From Table A-1

$$\text{Cost/Mile} = 65,400\ (1.3)$$

$$= 85,000$$

$$\text{Cost} = 85,000\ (10)(53.5 \text{ miles})$$

$$= 45,500,000$$

Table A-1
U. S. Pipeline Construction Costs 1969*

Pipe Size	Miles Laid	Dollar Costs per Mile		
		Minimum	Maximum	Average
8"	58.78	16,686	43,207	40,711
10"	117.20	32,424	112,616	50,207
12"	132.12	27,884	172,556	59,971
16"	32.30	57,390	167,196	78,131
20"	86.64	54,961	181,872	101,803
24"	327.04	81,269	381,194	171,919
26"	358.81	100,897	116,058	107,996
30"	815.27	129,121	459,330	175,169
36"	877.74	169,963	350,168	216,759
42"	504.51	252,923	757,059	267,363

*For overland pipelines

Source: Oil Pipeline Construction and Maintenance, vol. II, 2nd ed. Petroleum Extension Service, University of Texas, April 1973.

10. DETERMINING PIPELINE OPERATING COSTS

Pipeline operating costs have been estimated at 4 percent of construction costs. This would include costs to operate, monitor, maintain, and repair the pipeline over the life of the field.

Example: For Santa Rosa-Cortes (N)

Operating Costs = .04 (Construction Costs)

= (.04)(45,500)

= $1,820,000/year

11. DETERMINING PIPELINE LIFE CYCLE COSTS

Pipeline life cycle costs are determined by the same formula as that of tankers.

Example: For Santa Rosa-Cortes (North), life cycle costs are computed based on the following assumptions:

Capital Costs	= $45,500,000
Annual Operating Costs	= $1,820,000
Discount rate	= 10%
Interest Rate	= 10%
Inflation Rate	= 5%
Life Cycle	= 20 years

$$\text{Life Cycle Costs} = I + \sum_{N=1}^{20} O\,(.95)^{N-1}$$

$$= 45,500 \sum_{N=1}^{20} (1,820,000)\,(.95)^{N-1}$$

$$= \$68,181,000$$

12. DETERMINING COSTS PER BARREL FOR ALTERNATIVE TRANSPORT MODES

The cost per barrel for transporting the OCS crude oil can be determined by dividing the life cycle costs for the selected alternative by the estimated recoverable reserves.

Example: For Santa Rosa-Cortes (North) low estimate of reserves per barrel cost for tanker system

$$= \frac{\text{Life Cycle Costs}}{\text{Estimated Recoverable Reserves}}$$

$$= \frac{53,216,000 \text{ Dollars}}{242,000,000 \text{ Barrels}}$$

$$= .220 \text{ Dollars/Barrel}$$